YUKON ENERGY CORPORATION

YUKON UTILITIES BOARD REVIEW
IN THE MATTER OF
AN ELECTRICITY PURCHASE AGREEMENT
BETWEEN
YUKON ENERGY CORPORATION AND
TLINGET HOMELAND ENERGY LIMITED PARTNERSHIP

ROUND 1 INTERROGATORY RESPONSES FILED

March 9, 2022

CITY OF WHITEHORSE
(CW)

TOPIC: **Stranded Thermal Assets**

REFERENCE: **YEC Application PDF page 18 of 136, Section 4.1.**

PREAMBLE: **On PDF page 18, YEC states:**

> **The public need for the EPA under reasonable electric load forecasts is examined in the context of the Project's expected capabilities to supply YIS electric load to displace thermal generation. This approach allows YEC to secure through the EPA the Project's energy and dependable capacity benefits while the Project is owned and developed by THELP.**

As the proposed agreement will displace thermal assets, CW would like information to understand the treatment of existing thermal assets.

QUESTION:

a) Please fully explain what will happen to existing thermal assets, whose energy will be displaced by the EPA. Will YEC maintain all thermal assets, or will they be removed from rate base? Will there be any reduction to maintenance costs related to thermal assets?

b) Please fully explain whether the EPA will create any stranded assets.

ANSWER:

(a) and (b)

The EPA will not create any stranded YEC thermal assets.

Table 4-1 and Figure 4-1 of the Submission show 2021-2030 forecast non-industrial peak load and the forecast dependable capacity excluding mobile rented diesel units. This indicates a forecast YIS N-1 capacity shortfall for winter 2024/25 without the EPA of 17.2 MW related to non-industrial YIS load. Without the EPA and Moon Lake Pumped Storage, this capacity shortfall increases to 27.6 MW by 2027/28 (requiring 16 x 1.8 MW diesel

rental units, plus any spares needed to support these units), and then 41.5 MW by 2030/31 (requiring 24 rented diesel units).

As noted in the Submission, the EPA replaces the requirement for rental or new permanent diesel units. This would not change the requirement for YEC to continue to maintain thermal assets that it currently owns or plans to replace in order to ensure that it can continue to meet N-1 requirements.

TOPIC: **Pricing**

REFERENCE: **YEC Application, PDF page 28 of 136.**

PREAMBLE: **On PDF page 28, YEC indicates that the Capacity price is $200 per kW per year and the energy price is $0.19 / kWh.**

QUESTION:

a) Please fully explain how the proposed pricing for energy and capacity was developed.

ANSWER:

(a)

Please see response to YUB-YEC-1-24.

TOPIC: **Deliveries above LTA**

REFERENCE: **YEC Application PDF page 14 of 136.**

PREAMBLE: **At Item 3 of PDF page 3, YEC states:**

> **3. Delivery of all Winter Energy available: while YEC will only pay for winter energy that displaces LTA forecast thermal generation, YEC will take delivery each winter season (Sep-May) of all available energy that the Project is able to generate.**

CW requires information to better understand pricing proposed in the agreement.

QUESTION:

a) Please fully explain how the volumes above the LTA will be priced. In the response please fully explain why the price for surplus energy should not be priced at the YEC cost of hydro energy.

ANSWER:

(a)

Winter delivery volumes above the low flow year deliveries (25.2 GWh/yr), including winter volumes delivered above the LTA (30.8 GWh/yr), will all be priced using the Non-Firm Winter Energy Price (see Table 3-1 in YEC's Submission).

Please see responses to YUB-YEC-1-11, YUB-YEC-1-12 and YUB-YEC-1-24 for explanations as to how EPA energy prices were determined based on displaced thermal fuel generation costs.

In developing energy prices for IPP purchases (including purchases under the Atlin EPA) no estimates have been developed of YEC cost savings for reduced non-fuel O&M costs for thermal or hydro generation, i.e., the focus has remained on thermal generation fuel cost savings. EPA deliveries will result in some added YEC cost savings for displaced

thermal generation non-fuel O&M and (to a smaller degree) for displaced hydro generation due to increased spills at YIS hydro facilities.

TOPIC: **Cost to customers**

REFERENCE: **YEC Application, PDF page 18 of 136.**

PREAMBLE: **On PDF page 18, YEC states:**

> **The Minister's Terms of Reference state that the general purpose of this review of the EPA "is to obtain the YUB's report and recommendations on the potential benefits, costs, risks and customer impacts that influence whether the Agreement should proceed as proposed by YEC"**

CW requires information to assess the impact of the proposed agreement on end use customers. YEC discusses the cost of energy and the cost of capacity.

QUESTION:

a) Please provide a detailed analysis that demonstrates the total cost to a customer after the arrangement is complete. In the response please include:

- The cost of energy delivered under the EPA for LTA volumes.
- The cost of energy delivered in excess of LTA Volumes.
- The cost of capacity under the EPA.
- The asset costs related (Return, Income Tax, and Depreciation) to maintaining YEC Thermal to meet LTA volumes. (if any) (including any costs of leased assets)
- The operating costs related to maintaining YEC Thermal assets to meet LTA volumes.(if any) (including any costs of leased assets)
- The asset costs related (Return, Income Tax, and Depreciation) to maintaining YEC Thermal assets as backup. (including any costs of leased assets)
- The operating costs related to maintaining YEC Thermal assets as backup. (including any costs of leased assets)

b) Please provide a detailed analysis that demonstrates the current cost of thermal generation to a customer prior to the implementation of the EPA:

- The asset costs related (Return, Income Tax, and Depreciation) to own and operate YEC Thermal assets. (including any costs of leased assets).
- The operating costs related to owning and operating YEC Thermal assets as backup (including any costs of leased assets).

ANSWER:

(a) and (b)

YEC can only provide the relevant costs for YEC – developing costs "to a customer" is not feasible without spelling out as specific customer's load requirements and rates. Review of impacts on overall costs for YEC addresses the overall impact of the EPA on Yukon utility customer rates (given that rates for YEC and AEY are consolidated).

YEC also has developed costs only based on incremental changes due to the EPA, based on reasonable specified assumptions. It is not practical or cost effective to develop full YEC system costs for scenarios with and without the EPA.

Please see the following responses for EPA related information requested that is available:

- CW-YEC-1-2 for review of the specific EPA prices and how these were determined based on forecast YEC loads and costs for thermal fuel and new permanent diesel generation capacity.

- YUB-YEC-1-11, YUB-YEC-1-12 and YUB-YEC-1-24 for explanations as to how EPA energy prices were determined based on displaced thermal fuel generation costs.

- JM-YEC-1-10 (a) for simplified annual firm and non-firm energy as well as capacity payment example under the EPA for the years 2024-2065.

There is no impact from the EPA to the return or depreciation expenses of the current permanent thermal assets. The EPA impacts as follows:

- The energy deliveries from the EPA reduce the thermal generation requirements which in turn reduce thermal fuel costs and potentially non-fuel thermal

maintenance costs. For the EPA pricing only forecast thermal fuel cost reductions are used and no forecast maintenance cost savings are included [which would increase the EPA energy benefits – but note that non-variable O&M new diesel costs are included in the capacity pricing below].

- The EPA capacity delivery will reduce the N-1 capacity shortfall and reduce reliance on diesel rentals and/or the need for new permanent diesels. The capacity shortfall exists even with all existing thermal units [i.e., the EPA dependable capacity does not replace the dependable capacity that is being provided by the existing permanent thermal units]. The pricing for the EPA dependable capacity is based on levelized cost estimates for new diesel capacity, which address capital and non-variable O&M costs for new diesel over an assumed 40-year life – however, the levelized cost assessment does not reflect the cost profile for new diesel impacts on customer rates over this life (i.e., YEC owned new diesel assets compared with the equivalent EPA levelized costs would tend to have higher fixed cost impacts in the initial years and lower fixed cost impacts in later years due to standard methods for assessing return on rate base over an asset's life).

YEC does not own the rented diesel units, therefore does not earn a return or calculate depreciation expenses for the rental diesel units but pays rental related cost. The cost of diesel rentals was reviewed during the 2021 GRA as well as during BESS Part 3 hearing. YEC will continue to rely on diesel rental infrastructures built to accommodate diesel rentals until sufficient permanent dependable capacity is developed to address the growing capacity shortfalls.

TOPIC: **Reliability**

REFERENCE: **YEC Application, PDF page 33 of 136.**

PREAMBLE: **On PDF page 33, YEC states:**

> **The Project is expected to be highly reliable (i.e., only 2% unplanned downtime is applicable), given long-term evidence on water availability, the available Surprise Lake Storage, and the mature hydro generation technology being used. However, risks still remain, e.g., winter conditions along with climate change may lead to ice condition instability or other issues in any given year that reduce actual dependable capacity delivered during a PWP from what was confirmed in the December Dependable Plant Capacity Test used to set Dependable Capacity Payments for the PWP.**

CW requires information to understand the impact and remedy for unplanned outages.

QUESTION:

a) Please confirm that 2% unplanned outages equates to 175 hours per year. If not confirmed, please fully explain.

b) Please provide a detailed discussion of the remedies available to YEC for unplanned outages, including specific references to the EPA purchase agreement that include the remedies.

c) Please fully explain the impact of an unplanned outage, including how YEC would supply the power shortfall.

ANSWER:

(a)

Confirmed.

(b) and (c)

YEC will deal with an unplanned outage at the Atlin facilities (or required AEY transmission facilities) in the normal way it deals with unplanned outages for any source of generation. The methods will vary depending on the circumstances related to each outage. With respect to energy supply requirements, YEC has adequate thermal generation capability to address such events (and customer net cost impacts are expected to be minimal given the basis for determining EPA energy prices based on displaced thermal energy generation fuel cost savings). With respect to dependable capacity requirement, YIS reliability under the N-1 dependable capacity criterion requires sufficient back-up dependable capacity to meet winter peak load requirements with the loss of the Aishihik Generation Facility (37 MW).

Please also see the response to YUB-YEC-1-13(b and c) for review of backup provisions to maintain N-1 capacity.

With respect to EPA provisions for unplanned Atlin outages, YEC will not be required to pay THELP for any energy that is not delivered. With respect to dependable capacity, the EPA provisions for excess capacity payment recoveries under section 8.3 of the EPA will also be applied.

TOPIC: **Impact On Rate Base**

REFERENCE: **YEC Application, PDF page 29 of 136.**

PREAMBLE: **On PDF page 29, YEC states:**

> **There is some uncertainty with respect to what, if any impact the EPA may have on YECs balance sheet (i.e., rate base). Based on preliminary assessments of the Agreement, YEC has concluded that this transaction does not contain a capital lease and therefore there is no balance sheet or rate base impact. This conclusion, however, is not final. The ultimate impact can only be known when the Project is complete and YECs auditors (the Auditor General of Canada) have reviewed the transaction.**

CW would like to better understand what the rate base impacts could be if YEC's preliminary conclusion proves to be incorrect.

QUESTION:

a) Please fully explain the range of potential impacts on YEC's balance sheet if YEC's preliminary conclusion of no impact proves incorrect.

b) What is the greatest rate base impact possible?

ANSWER:

(a) and (b)

Please see response to YUB-YEC-1-42.

TOPIC: **ATTACHMENT A: EPA Article 2 Conditions Precedent**

REFERENCE: **YEC Application, PDF page 67 of 136.**

PREAMBLE: **Section 2.1 (d) sets out the Conditions Precedent. The Condition Dates for the first two of these have passed. CW would like a status update.**

QUESTION:

a) Has the Condition Precedent in Section 2.1 (d) (i) been met? If yes, please provide a copy of the referenced Interconnection Agreement. If no, please explain the status and any impact flowing from the failure to meet this Condition Precedent by the Condition Date

b) Has the Condition Precedent in Section 2.1 (d) (ii) been met? If no, please explain the status and any impact flowing from the failure to meet this Condition Precedent by the Condition Date.

ANSWER:

(a) and (b)

YEC and THELP have agreed to extend the dates for the satisfaction of the following conditions precedent in the EPA:

- 2.1 (d)(i) and (ix) extended from January 31, 2022 to March 31, 2022;
- 2.1(d)(ii) extended from February 15, 2022 to April 30, 2022
- 2.1(d)(vii) extended from February 28, 2022 to May 31, 2022.

The Interconnection Agreement is in the process of being finalized and this is now expected to occur before March 31, 2022. As the condition has been extended there is no impact flowing from the failure to meet this Condition Precedent by the Condition Date. This extension (as well as the other extensions noted above) also have no impacts on the overall schedule for concluding the EPA conditions precedent.

The Interconnection Agreement will include final scoping of the Buyer-AEY System Upgrades and budgeted costs for the Buyer-AEY System Upgrades will be determined subsequent to the finalization of that agreement. As the condition has been extended there is no impact flowing from the failure to meet this Condition Precedent by the Condition Date.

JOHN MAISSAN
(JM)

TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 2 bottom and page 3 top: "A 92 km 69 kV new transmission line from a new substation at the new hydro facilities to a new interconnection substation at Jakes Corner, YK with interconnection to the YIS at the existing 34.5 kV ATCO Electric Yukon ["AEY"] facilities ["AEY System"] for transmission to YEC's S-150 substation in Whitehorse."**

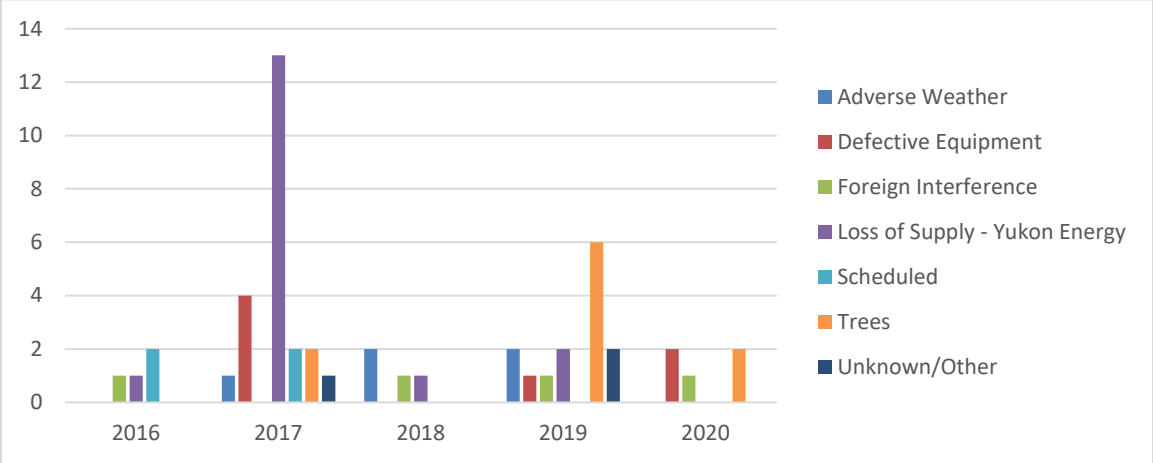
QUESTION:

a) Please provide the reliability criteria for this portion of ATCO power line and compare this to similar criteria for YEC's 138 kV and 69 kV power lines.

ANSWER:

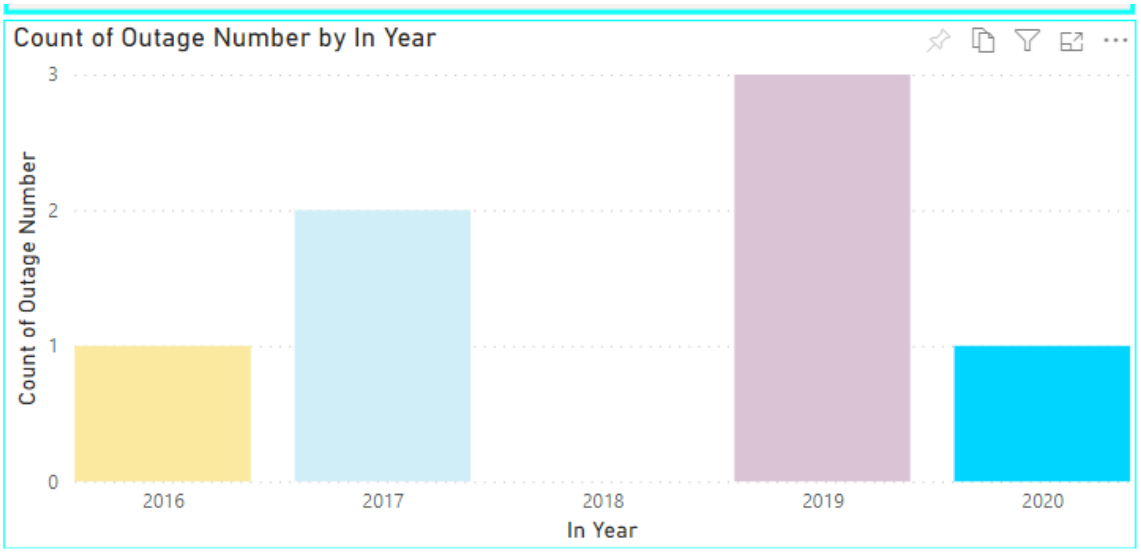
(a)

Outage statistics – AEY Line 6L11

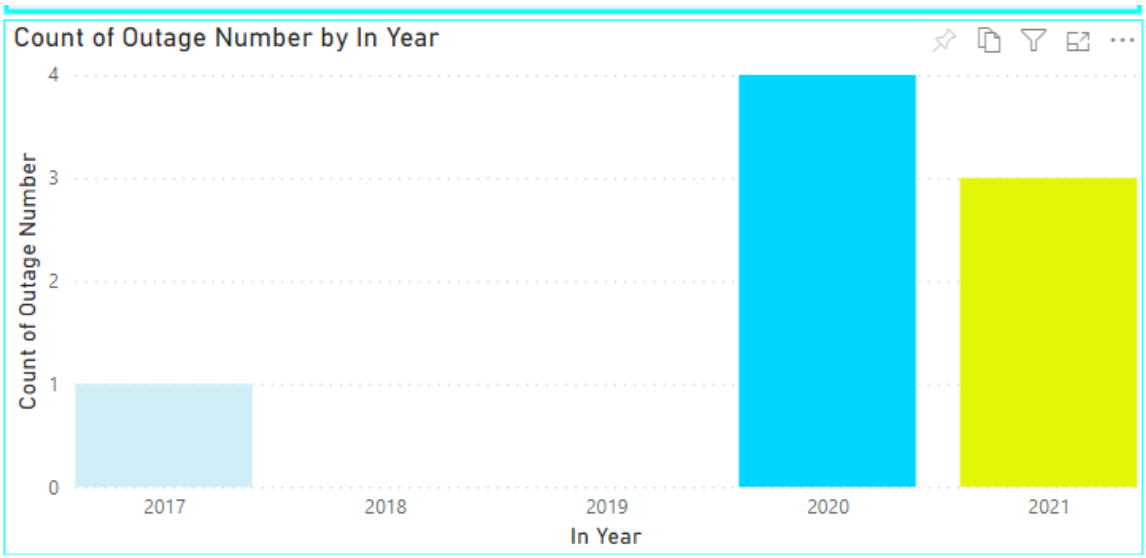


The question is not specific with respect to which YEC line to compare; YEC does not have consolidated data so the following graphs are from sample lines – i.e., for 138 kV – L171 – Aishihik to Takhini; for 69 kV – L176/7 – Mayo to Dawson

L171 – Aishihik to Takhini



L176/7 – Mayo to Dawson



TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 3 Figure 2-1**

QUESTION:

a) Please provide a digital higher resolution version of Figure 2-1 so that all the project components can be clearly seen.

b) Will the new Atlin Project have a different penstock than the existing plant, and if so, will they come from the same head pond?

ANSWER:

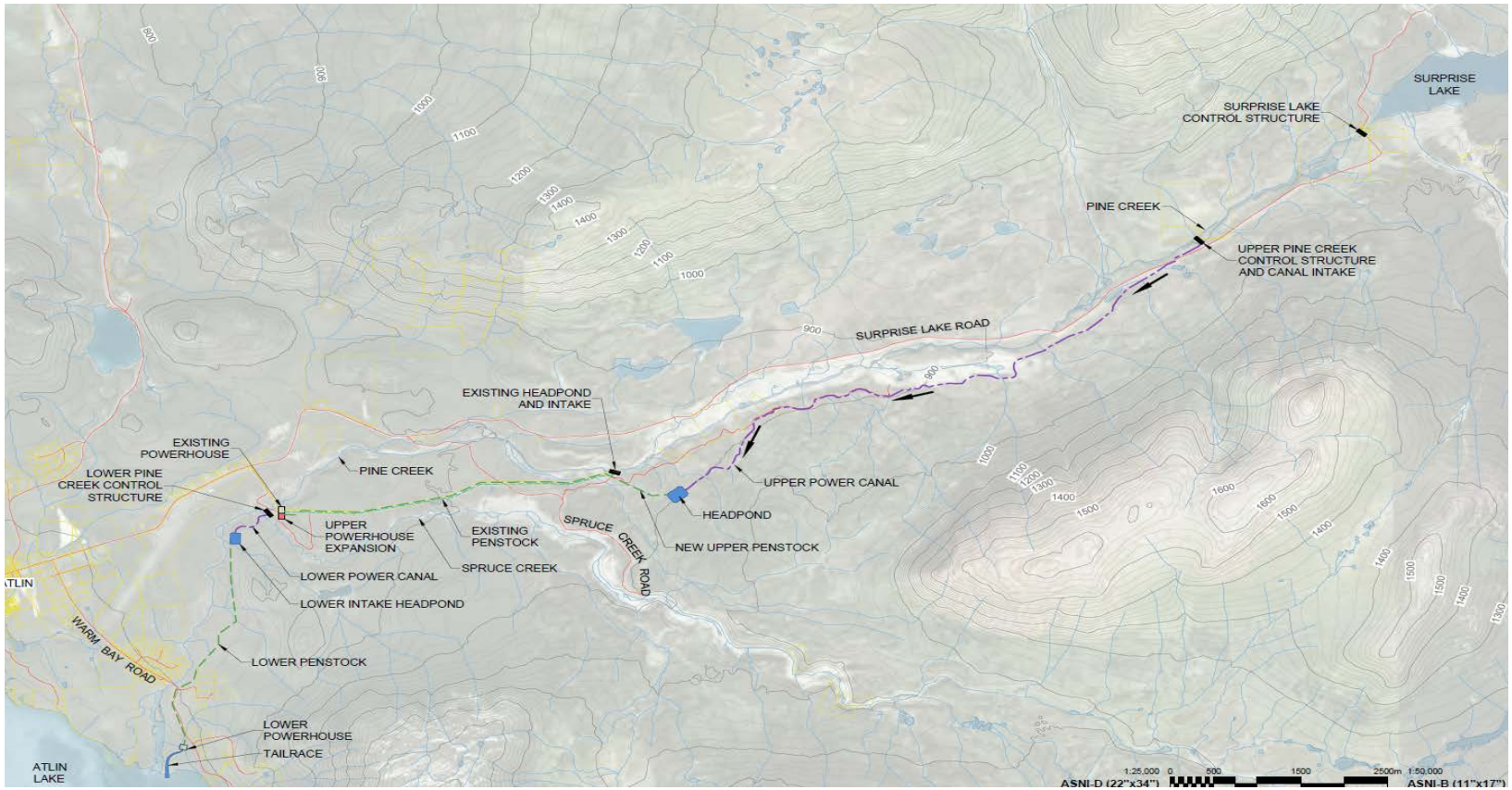
(a)

Appendix 1 provides an expanded Figure 2-1 so that all project components can be clearly seen.

(b)

The Atlin Project will have a different penstock than the existing plant, with a different head pond. The beginning of the new upper powerhouse penstock is shown in Figure 2-1 attached – the new penstock then continues to the upper powerhouse beside the existing penstock.

Appendix 1 - Expanded Figure 2-1



TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 4: "…which is more than enough days to cover the 20 or less [sic] days of the PWP period when minus 30°C or lower temperature has been recorded at Whitehorse."**

QUESTION:

a) Please confirm that this is a 24-hour day, and explain what a day with minus 30°C temperature at Whitehorse is – is it a day in which the temperature reached minus 30°C at any time in the day, or in which the mean or average daily temperature is minus 30°C or lower, or in which the temperature stays below minus 30°C for the entire day?

b) Please confirm that there were no days at minus 30°C or colder outside of the Peak Winter Period in years over which the temperature records were examined by YEC.

ANSWER:

(a)

It is the average daily temperature drop below -30ºC as clarified in footnote #7 on page 4 as well as in Appendix B, page B-3. For example, page B-3 of Appendix B shows that in in 2009 the average daily temperatures dropped below -30ºC for 10 days and in 2020 nine days. The table below shows the details of temperature recorded for those days.

Day	Max Temp (°C)	Min Temp (°C)	Mean Temp (°C)	Day	Max Temp (°C)	Min Temp (°C)	Mean Temp (°C)
Jan-01-2009	-26.2	-39	-32.6	Jan-10-2020	-28.8	-33.3	-31.1
Jan-02-2009	-34.8	-40.9	-37.9	Jan-11-2020	-33.2	-36.6	-34.9
Jan-03-2009	-32.9	-36.8	-34.9	Jan-12-2020	-33.9	-39.2	-36.6
Jan-04-2009	-27.5	-34.1	-30.8	Jan-13-2020	-35.4	-40.3	-37.9
Jan-05-2009	-26.2	-34.1	-30.2	Jan-14-2020	-35.4	-40.6	-38
Jan-06-2009	-31.7	-39.3	-35.5	Jan-15-2020	-32.6	-38.1	-35.4
Jan-07-2009	-34.3	-40.7	-37.5	Jan-16-2020	-33	-36.8	-34.9
Jan-08-2009	-33.9	-38.5	-36.2	Jan-17-2020	-34.5	-39.1	-36.8
Jan-09-2009	-29.2	-34.6	-31.9	Jan-18-2020	-32	-40.4	-36.2
Jan-10-2009	-28.5	-33	-30.8				

(b)

The historical weather data reviewed from 1991 through 2021 shows the average daily temperatures dropped below -30ºC only during the Peak Winter Period, except for the following four years [4 out of 31 years]:

- 1995 the temperature dropped below -30ºC for December 4-9 (6 days);
- 2006 the temperature dropped below -30ºC for November 24-28 (5 days);
- 2012 the temperature dropped below -30ºC for November 29 (1 day); and
- 2016 the temperature dropped below -30ºC for December 13-15 (3 days).

In each case the -30ºC temperature lasted no more than six days.

TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 4 Footnote 7:**

QUESTION:

a) Is a minus 38°C day defined in a manner consistent with the answer to JM-YEC-1-3?

b) Why is the Yukon Energy (YEC) non-industrial peak load relevant?

c) If it is relevant, is it relevant for the N-1 capacity requirement criterion for the non-industrial peak load only?

d) Are the total peak load and energy requirements with industrial customers not much more relevant for the thermal energy displacements that are calculated in YEC's submission and on which the purchase price for energy is based? Please explain in detail.

ANSWER:

(a)

Yes, it is the average daily temperature drop below -38ºC.

(b) and (c)

Non-industrial peak load is the relevant load for the single contingency dependable capacity requirement criterion (see below). This criterion has been used to assess the required dependable capacity from the Atlin Project.

Yukon Energy's generation capacity planning criterion for the YIS is based on the single contingency (N-1) dependable capacity criterion, under which the YIS is required to have enough dependable capacity to supply the forecast non-industrial peak winter demand under the largest single contingency. This criterion considers the ability to interrupt large

industrial customers during an emergency event, which is why only non-industrial peak demand is included. Therefore, the N-1 dependable capacity shortfall is due to increase in non-industrial peak.[1]

There is also a direct correlation between non-industrial peak and prolonged cold weather as non-industrial peak is primarily driven by residential demand for services such as space heating along with other residential uses. Yukon's electricity demand typically peaks during or shortly after prolonged periods of cold winter days. YEC experienced a record peak in January 2020 when over nine days the average daily temperature remained below -30ºC [please see response to JM-YEC-1-3].

(d)

The peak demand non-industrial load is only considered for the dependable capacity requirement and EPA benefits from displacement of new thermal generation capacity (permanent new units or rental diesel units). All firm load (including industrial) is considered for assessing EPA energy benefits in displacing thermal generation.

There are two benefits from the EPA for the YIS:

- The Project provides dependable capacity otherwise expected to be required by using new thermal generation capacity (permanent new units or diesel rentals).

- The Project displaces thermal generation energy.

Therefore, the EPA includes separate pricing for each of the benefits outlined above, i.e., capacity and energy pricing:

- **Dependable Capacity Payment**: YEC pays THELP the Dependable Capacity Payment for each PWP based on the Dependable Plant Capacity Committed [Dependable Capacity Price of $200/KW per year (2024$) as escalated at CPI after

[1] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied so long as the single contingency, N-1, criterion was met. N-1 capacity shortfall is also impacted by retirement of the existing generation units and/or changes in operation conditions [e.g., winter flow restrictions for hydro generation units].

2024]. The requirement for this dependable capacity is driven by N-1 capacity criterion which is based on non-industrial peak as reviewed in response to the previous question in this IR.

- **Winter Energy Delivery**: YEC pays THELP for delivered energy based on Firm Winter Energy Price of $0.132/kWh for 2024-2034 [$0.107/kWh for 2035 and thereafter], and Non-Firm Winter Energy Price of $0.072/kWh for 2024-2034 [$0.027/kWh for 2035 and thereafter] all in 2024$ and increased by 50% of CPI for each year. These firm and non-firm energy pricings are determined based on total YEC load, including industrial load as reviewed in Tables A3-1 and A3-2 in Appendix A [i.e., LTA thermal energy displacements are determined including industrial load].

TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 5 top: "Expected Winter Period deliveries to YEC per calendar year are 30.8 GWh LTA energy and 25.2 GWh firm energy during the lowest water year."**

And: YEC 2021 GRA Table 2.2 on page 2-17 which shows on line 27 long term average (LTA) forecast thermal generation at 15.6% (84,306/538,726) and actual thermal generation on line 21 plus line 22 at 5.6%.

QUESTION:

a) Has YEC calculated the correlations of the Atlin Surprise Lake water years with each of the following and if so, please provide the results, and if not please explain why not.
   i. Whitehorse hydro
   ii. Aishihik hydro
   iii. Mayo hydro, and
   iv. The YIS hydro as a whole (excluding Fish Lake).

b) Please discuss what a correlation or a lack of correlation between the Atlin project and any or all of the YEC hydro plants would mean for thermal energy displacement.

c) If YEC has not used correlations, please explain how YEC has ensured that its thermal energy displacement calculations were as accurate as possible.

d) Does YEC still use weekly time step modelling for potential new projects such as this one

e) In the YEC 2017-2018 GRA, IR JM-YEC-2-6 and in the transcript at pages 211-212, hourly time step modelling was discussed. Does YEC now have an hourly time step model, and if so, was it used in calculating thermal displacements at times when thermal generation is only used for portions of the day? And if not how did YEC ensure thermal displacement calculations at such times were accurate

particularly with the assumed 39.9 GWh per year of intermittent (predominantly solar) IPP SOP generation (page A-3 Table A3-1)?

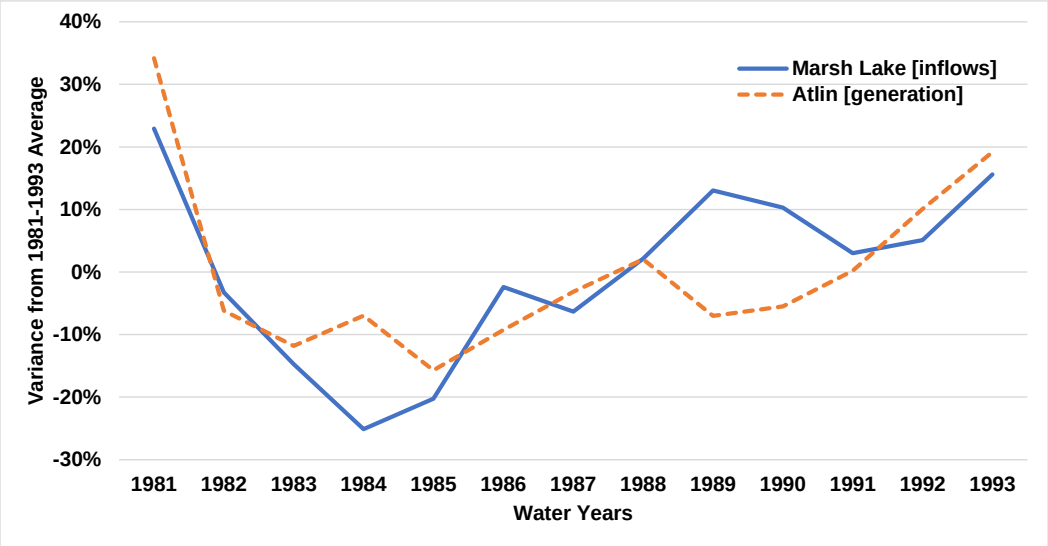
ANSWER:

(a) through (c)

YEC has not calculated the correlations asked about in this question. Available information is reviewed below. The thermal energy displacement calculations utilize 38 water years of simulated weekly YIS hydro generation that include the YIS as a whole, and provide estimates that are as accurate as possible based on the current information.

The geographical position and catchment area of Aishihik and Mayo hydro storage facilities are significantly different from Surprise Lake. There is no basis for assuming any material correlation between Atlin and YEC's Aishihik or Mayo hydro facilities.

There are, however, similarities between basins for Whitehorse Hydro storage facilities and Atlin. The figure below illustrates correlation of Marsh Lake inflows for 1981-1993 water years to simulated Atlin generation for the same water years.[1]



[1] As illustrated in Table A1 in Appendix A Atlin generation estimates are available for 1963-1993 and 2015-2019 water years. YEC LTA hydro generation estimates are based on 1981-2018 water years. The figure uses 1981-1993 years which are available for both Marsh Lake and Atlin.

Yukon Energy believes the approach that was used in determination of EPA pricing mutes any impact of lack of correlation of available storage over water years and storage facilities considering the following factors:

- The LTA thermal displacement benefits are determined using Atlin generation based on long-term average water conditions [the average Atlin hydro generation for all water records]; they were also separately determined using only low water year generation deliveries that reflect the lowest Atlin hydro generation in water year 1978.

- The EPA energy pricings were determined based on firm and non-firm energy deliveries.
    - The firm energy pricing reflects estimated LTA thermal displacement based on only the firm hydro generation that can be delivered by the Project during low water conditions [i.e., the lowest annual hydro generation over all 35 water years]. This is a factor which will tend to reduce impacts for YEC from variances in LTA vs low water year energy deliveries.
    - The non-firm energy pricing determined based on only the added benefits from LTA hydro in excess of generation in the lowest water year.

- The LTA thermal displacement benefits are based on 38 water years of hydro availability for all Yukon Energy hydro generation storage facilities [i.e., takes into account variation in seasonality and water availability of Whitehorse, Aishihik and Mayo hydro generation storage facilities].

- The analysis utilizes LTA renewable generation through the year for assessing impacts of new renewable generation, including SOP IPP generation and the Atlin EPA.

(d)

Yes. The LTA thermal displacement benefits are determined using the YECSIM model which uses weekly time steps (including LTA weekly time step assessments for all new renewable projects such as the Atlin project that are included in the benefit assessment).

(e)

The LTA thermal displacement benefits of the Atlin project estimated using the YECSIM model reflect seasonality of the intermittent resources such as wind and solar IPPs. The weekly load shapes were developed for each IPP resource which affects the LTA thermal requirements.

YEC does not expect that the daily/hourly variations of the IPPs will have significant impact to the thermal displacement benefits considering:

- The impacts, if any, of the daily/hourly variances affect the LTA thermal generation under both with and without Atlin project [i.e., the delta is not impacted significantly].

- A long-term average over 38 water years has been used for the calculations of LTA thermal displacement benefits reducing the impact, if any, of the daily/hourly variances.

TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 6 Figure 2-4**

QUESTION:

a) For the YIS Please provide a table of monthly actual hydro generation, actual other renewable energy generation (microgeneration, IPP SOP, etc.), actual thermal generation, and actual total generation excluding any secondary sales; plus additional columns (or rows) for actual secondary sales generation and "spilled" surplus (potential) generation for each the years 2017 to 2021 inclusive. The months may be placed in rows and the generation sources in columns or vice versa as is most convenient for YEC.

b) Please provide similar tables for the YIS for the years 2024 and 2035 as forecast and assumed in preparing this EPA.

ANSWER:

(a) and (b)

Please see Table 1 for actual generation by source for 2017-2021 and Table 2 for the forecast generation used for Atlin EPA thermal displacement analysis.

Please note that YEC does not administer the microgeneration program and therefore does not have the actual generation numbers. The microgeneration totals are embedded in actual generation numbers [i.e., the actual generation numbers reflect reduced load due to microgeneration load generated by customers].

The forecast incremental microgeneration numbers are provided to YEC by the Department of Energy, Mines and Resources.

Table 1: 2017-2021 YEC Actual Generation

	Month	Hydro	YEC Wind	IPPs	Thermal	Total Firm Generation	Secondary Sales Generation	Total Generation
		[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
2017	January	46.47	0.00	0.00	2.70	49.18	0.38	49.56
	February	38.33	0.00	0.00	1.79	40.12	0.98	41.10
	March	39.81	0.00	0.00	2.46	42.27	0.05	42.32
	April	33.73	0.00	0.00	0.02	33.75	1.00	34.75
	May	33.12	0.03	0.00	0.11	33.26	1.06	34.32
	June	28.39	0.00	0.00	0.16	28.55	0.81	29.36
	July	28.50	0.00	0.00	0.13	28.63	1.21	29.84
	August	29.67	0.00	0.00	0.22	29.90	0.84	30.73
	September	27.73	0.00	0.00	0.66	28.39	0.80	29.20
	October	38.25	0.00	0.00	0.06	38.31	0.59	38.91
	November	45.02	0.00	0.00	1.46	46.48	0.89	47.37
	December	42.93	0.00	0.00	4.70	47.63	0.48	48.11
	Total	**431.95**	**0.03**	**0.00**	**14.47**	**446.46**	**9.09**	**455.55**
2018	January	44.91	0.00	0.00	5.54	50.46	0.00	50.46
	February	40.27	0.00	0.00	7.09	47.36	0.00	47.36
	March	34.43	0.00	0.00	6.33	40.76	0.00	40.76
	April	33.85	0.00	0.00	5.69	39.55	0.00	39.55
	May	28.32	0.00	0.00	1.13	29.45	0.00	29.45
	June	29.98	0.00	0.00	0.41	30.39	0.02	30.40
	July	29.54	0.00	0.00	0.34	29.89	0.02	29.91
	August	31.39	0.00	0.00	0.09	31.49	0.16	31.65
	September	29.66	0.00	0.00	0.01	29.67	0.08	29.75
	October	35.78	0.00	0.00	1.93	37.71	0.00	37.72
	November	36.23	0.00	0.00	2.80	39.02	0.00	39.02
	December	38.40	0.00	0.00	5.94	44.34	0.00	44.34
	Total	**412.77**	**0.00**	**0.00**	**37.32**	**450.09**	**0.28**	**450.37**
2019	January	40.21	0.00	0.00	7.56	47.77	0.00	47.77
	February	36.99	0.00	0.00	7.44	44.43	0.00	44.43
	March	27.22	0.00	0.00	8.57	35.78	0.00	35.79
	April	25.04	0.00	0.00	9.61	34.65	0.00	34.65
	May	20.97	0.00	0.00	7.71	28.68	0.00	28.68
	June	24.57	0.00	0.00	1.41	25.97	0.00	25.97
	July	29.22	0.00	0.00	0.16	29.38	0.00	29.38
	August	29.01	0.00	0.00	0.06	29.07	0.00	29.07
	September	31.02	0.00	0.00	1.02	32.04	0.00	32.04
	October	32.81	0.00	0.00	7.29	40.10	0.00	40.10
	November	33.41	0.00	0.00	8.75	42.16	0.00	42.16
	December	40.35	0.00	0.00	10.29	50.64	0.00	50.64
	Total	**370.82**	**0.00**	**0.00**	**69.86**	**440.68**	**0.00**	**440.68**
2020	January	41.51	0.00	0.00	17.15	58.66	0.00	58.66
	February	38.49	0.00	0.00	9.80	48.29	0.00	48.29
	March	35.11	0.00	0.00	11.98	47.09	0.00	47.09
	April	27.79	0.00	0.00	11.51	39.29	0.00	39.29
	May	27.67	0.00	0.00	5.10	32.77	0.00	32.77
	June	30.99	0.00	0.00	1.13	32.12	0.00	32.12
	July	33.14	0.00	0.00	0.04	33.18	0.00	33.18
	August	33.10	0.00	0.00	0.05	33.14	0.00	33.14
	September	32.06	0.00	0.00	0.98	33.03	0.00	33.03
	October	41.21	0.00	0.00	0.61	41.82	0.66	42.47
	November	47.78	0.00	0.00	4.96	52.74	0.00	52.74
	December	46.53	0.00	0.00	6.13	52.66	-0.46	52.20
	Total	**435.36**	**0.00**	**0.00**	**69.44**	**504.79**	**0.19**	**504.98**
2021	January	43.65	0.00	0.00	5.00	48.65	0.00	48.65
	February	47.38	0.00	0.00	10.64	58.02	0.00	58.02
	March	47.91	0.00	0.00	0.88	48.79	0.00	48.79
	April	41.75	0.00	0.00	1.17	42.92	0.00	42.92
	May	34.22	0.00	0.00	0.60	34.82	0.00	34.82
	June	34.82	0.00	0.00	0.02	34.84	2.12	36.97
	July	31.63	0.00	0.00	0.15	31.79	0.46	32.25
	August	35.63	0.00	0.00	0.48	36.11	0.41	36.52
	September	33.95	0.00	0.00	0.36	34.30	0.28	34.58
	October	41.87	0.00	0.00	0.74	42.62	0.96	43.58
	November	46.55	0.00	0.00	5.60	52.15	0.74	52.89
	December	48.76	0.00	0.00	13.57	62.34	0.13	62.47
	Total	**488.13**	**0.00**	**0.00**	**39.22**	**527.35**	**5.11**	**532.46**

Table 2: 2024 and 2035 Forecast Generation

	Month	LTA Hydro	Atlin [net of losses]	Total IPPs and Incremental Microgen	LTA Thermal	Total Firm Generation
		[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
2024	January	39.19	5.47	4.33	2.07	51.07
	February	36.70	4.98	3.45	2.12	47.25
	March	38.48	3.60	3.53	3.24	48.85
	April	33.36	1.49	3.24	3.33	41.41
	May	31.90	2.09	4.13	1.17	39.29
	June	33.77	0.00	2.50	0.08	36.35
	July	34.73	0.00	2.24	0.09	37.06
	August	33.79	0.00	3.80	0.00	37.59
	September	33.29	2.51	3.13	0.01	38.94
	October	41.23	1.98	3.01	0.21	46.43
	November	44.01	2.56	3.38	1.11	51.06
	December	42.87	4.18	3.19	2.32	52.56
	Total	**443.31**	**28.85**	**39.93**	**15.76**	**527.85**
2035	January	40.63	5.47	4.33	0.69	51.13
	February	37.68	4.98	3.45	1.04	47.16
	March	36.40	3.60	3.53	1.14	44.67
	April	30.88	1.49	3.24	1.15	36.75
	May	27.93	2.09	4.13	0.18	34.33
	June	28.50	0.00	2.50	0.00	31.00
	July	29.51	0.00	2.24	0.00	31.75
	August	28.52	0.00	3.80	0.00	32.32
	September	27.92	2.51	3.13	0.00	33.56
	October	36.55	1.98	3.01	0.00	41.54
	November	40.38	2.56	3.38	0.02	46.34
	December	44.84	4.18	3.19	0.30	52.52
	Total	**409.75**	**28.85**	**39.93**	**4.53**	**483.07**

See Table A3-1 in the Submission for annual summaries. Atlin LTA winter deliveries to Jakes Corner are 30.8 GWh (row 1 in Table A3-1); Atlin deliveries for LTA thermal displacement assessments with YECSIM assume 6.2% losses for transmission on AEY System from Jakes Corner to Whitehorse S150 (row 2 in Table A3-1).

TOPIC: **Section 2 Overview of the Project**

REFERENCE:

PREAMBLE: **Page 6: "Project capital costs have been estimated to date at approximately $206 million."**

QUESTION:

a) If YEC were to complete a project identical in all respects to the Atlin Project, including a 40-year life, for $206 million without any grant funding what would be the levelized cost of energy (LCOE) for all energy produced, and for the energy that is forecast to displace thermal generation only.

b) What would be the levelized cost of capacity (LCOC)?

c) Please repeat the calculations provided in (a) and (b) above for a project with a net capital cost of $56 million.

ANSWER:

(a) through (c)

Please see the table in Appendix A. The analysis assumes the Project is located at Atlin with same energy deliveries at Jakes Corner.

Appendix A

	No Grant	With Grant
With Annual Energy		
Project LCOE ($/kWh)	$0.298	$0.125
Project LCOC ($/MW)	$1,249,285	$510,942
With LTA Thermal Displaced Energy		
Project LCOE ($/kWh)	$0.548	$0.227
Project LCOC ($/MW)	$1,249,285	$510,942

Notes re: assumptions for YEC owned project at the Atlin location, same generation and transmission as per THELP Atlin Hydro Expansion Project:

1. Total capital cost assumed at $206 million [2024$].
2. Grant amount assumed at $150 million [2024$].
3. Fixed O&M at $2.0 million/year [2024$] – reflects approximately 1% of hydro plant capital cost plus provision for BC water rental charges with allowance for efficiencies due to existing hydro facilities plus an allowance for transmission O&M [THELP's estimate for this cost is slightly lower to reflect internal efficiencies when operating with the Existing Plant].
4. Variable non-fuel O&M at $5/MW [2024$].
5. Dependable capacity at 8.5 MW.
6. Annual energy at 36.2 GWh and LTA thermal displacement benefits at 19.6 GWh.
7. Weighted Average Cost of Capital at 4.79% (YEC 2021 GRA WACC) and inflation at 2%.
8. The life of the project assumed at 40 years.
9. The LCOE and LCOC at 2024$.

LCOE with LTA thermal displaced energy: This LCOE shows the levelized cost of energy for the portion that is useful in displacing LTA thermal generation at a given load [i.e., although the Project can generate 36.2 GWh of energy annually on a long-term basis, only 19.6 GWh is useful in displacing LTA thermal and the remaining LTA portion either is spilled or will result in spillage in other hydro storage facilities]. The LTA displaced energy at 19.6 GWh is based on assumptions noted in Table A3-1 in Appendix A of the Submission, and will change depending on the load and other renewable resources on

the YIS. For example, the lower load forecast for 2035 as per Table A3-1 of the Submission shows lower LTA thermal displacement benefits at 15 GWh.

TOPIC: **Section 3 Overview of the Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page 8 sub-section 3.1**

QUESTION:

a) Please provide a copy of the Buyer-AEY System Interconnection Study Report if now concluded. If not yet concluded, please provide a copy when it is concluded.

b) During the Peak Winter Period (PWP):
   i. what will be the power flows toward Teslin from Jake's Corner and towards Whitehorse?
   ii. what will be the power flows towards Whitehorse from north of the North M'Clintock road?
   iii. what will be the power flows towards Whitehorse north of the Carcross cut-off?
   iv. what will be the power flows at the YEC S150 substation?

ANSWER:

(a)

The "Buyer-AEY System Interconnection Study Report" is a schedule to the Interconnection Agreement that has not yet been completed. It will include:

1. The scope and planning level cost estimates for YEC and AEY system upgrades;

2. The electrical facilities or activities at the Interconnection Substation and other Seller's Plant, that Seller is to provide at its cost in compliance with the Interconnection Standards; and

3. The process for finalizing outstanding issues regarding the above scope and associated costs by April 30, 2022.

The response to YUB-YEC-1-9(a) provides the current planning level cost estimates for YEC and YEC system upgrades.

(b)

i. Jake's Corner (JC) towards Teslin: 2.452 MW at JC side
Jake's Corner towards Whitehorse: ~6 MW with only 1.90 MW delivered at Whitehorse S150 substation (several loads along S150–Jake Corner's path + line losses).

ii. North M'Clintock road is fed from a single phase 14.4kV distribution out of the South M'Clintock Substation, 500kVA, 34.5kV – 14.4kV. This substation is single phase and not a significant load, it feeds Army Beach, M'Clintock River Road and North M'Clinctock/Swan Haven. It is modelled as part of the load at Carcross Cut-off. See question "b" sub-question "iii"

iii. 4.78 MW out of Carcross Cut-off towards MacRae.
1.945 MW through MacRae towards Whitehorse S150

iv. From Jake's Corner: 1.90 MW
From P126 Whitehorse Diesel: 4.98 MW
From S171 Riverside (through Whitehorse S150 138 kV): 24.49 MW
From Whitehorse P125: 11.6 MW

TOPIC: **Section 3 Overview of the Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page 11 near top: "Delivery of all Winter Energy available: while YEC will only pay for winter energy that displaces thermal generation, YEC will take delivery each winter season (Sept-May) of all available energy that the Project is able to generate." and**

Page 12 "Delivered Energy", and

Page 14 Table 3.1

QUESTION:

a) The page 11 reference states that YEC will only pay for winter energy that displaces thermal generation but the page 12 reference and the pricing in Table 3-1 implies that non-firm winter energy (all available energy?) is paid for but at reduces rates. Please clarify this apparent discrepancy.

ANSWER:

(a)

The principle #2 at page 11 is that the EPA price is based on YEC only paying for forecast thermal generation displaced by winter energy (e.g., LTA displacement of 19.6 GWh for 2024). Principle #3 then states that YEC purchases all available winter energy that THELP provides (LTA deliveries of 30.8 GWh).

The two principles are reconciled by setting the energy price appropriately.

- LTA displacement in 2024 equals only approximately 63.5% of LTA deliveries.

- The average energy price paid of all energy delivered is then set at 63.5% of the thermal blend fuel price, i.e., YEC's payment is based on only paying for forecast thermal generation displaced.

Please see the response to YUB-YEC-1-11 and YUB-YEC-1-12 for more detailed review as to the determination of winter energy prices (including firm and non-firm prices).

TOPIC: **Section 3 Overview of the Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page 11 "Reliance of forecasts and forecast risk"**

QUESTION:

a) This section appears a bit confusing. Please provide a table of energy costs by year for each of the 40 years of the Electricity Purchase Agreement (EPA) starting in 2024 and finishing in 2065 with YEC forecast loads as in the EPA. Assume no summer energy purchase, no carbon tax, and LTA water availability in each year, i.e. 30.8 GWh per winter energy purchase. Assume an inflation rate and CPI of 2% per year including on the YUB Price of $0.19 per kWh. Please show each cost component (as per Table 3-1 on page 14) separately and the total cost.

b) Please provide a similar table for the 40 years with the mining load continuing to 2044. Assume the same non-industrial load growth as in (a) above.

c) Please provide a similar table for the 40 years with the mining load terminating in 2029. Assume the same non-industrial load growth as in (a) above.

d) For each of (a) to (c) can an LCOE using the total cost be calculated? If so, please provide these calculations.

ANSWER:

(a) and (c)

Please see the table below for requested information. Please also see response to JM-YEC-1-16. For simplicity, full LTA deliveries assumed each calendar year (commissioning in October is ignored) and capacity payments are recorded fully for each calendar year.

The following is noted regarding the table provided below:

- The EPA pricing assumes the mine load continues to 2034 and uses 2024 load forecast for 2024-2034 years. Therefore, the pricing and payments would be the same as for questions a) and c). Added Load sharing commences starting in 2035.

- The CPI assumed at 2% for energy and capacity rate calculations.

- Non-industrial winter load of 388 GWh forecast for 2035 is assumed to increase at 0.12%/year after 2035.

- The YUB price is assumed at $0.19/kWh [2024$] with inflation at 2%/year as stipulated in the question.

- The rate for Added Load is calculated as per EPA provision. For example, in 2065 the Added Load is 14.2 GWh and therefore the Added Load rate is $0.023/kWh [$0.19 x inflation = $0.428 x 11.7% * 14.2 / 30.8]. This rate is applied to energy delivered (30.8 GWh assumed each year).

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.132	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Non-Firm Winter Energy	0.072	0.073	0.073	0.074	0.075	0.076	0.076	0.077	0.078	0.079	0.080
Energy Payment, $million	3.725	3.762	3.800	3.838	3.876	3.915	3.954	3.993	4.033	4.074	4.114
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	200	204.0	208.1	212.2	216.5	220.8	225.2	229.7	234.3	239.0	243.8
Dependable Capacity Payment, $m	1.600	1.632	1.665	1.698	1.732	1.767	1.802	1.838	1.875	1.912	1.950
Total Payment, $million	**5.325**	**5.394**	**5.464**	**5.536**	**5.608**	**5.681**	**5.756**	**5.831**	**5.908**	**5.986**	**6.065**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.119	0.121	0.122	0.123	0.124	0.125	0.127	0.128	0.129	0.131	0.132
Non-Firm Winter Energy	0.030	0.030	0.031	0.031	0.031	0.032	0.032	0.032	0.033	0.033	0.033
Energy Payment, $million	3.173	3.204	3.236	3.269	3.302	3.335	3.368	3.402	3.436	3.470	3.505
Added Winter Load, GWh		0.5	0.9	1.4	1.9	2.3	2.8	3.3	3.7	4.2	4.7
Added Load Rate [YUB price $0.19/kWh]		0.000	0.001	0.001	0.002	0.002	0.003	0.003	0.004	0.005	0.005
Added Load Rate Payment, $m		0.013	0.027	0.041	0.056	0.071	0.087	0.104	0.121	0.139	0.158
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	248.7	253.6	258.7	263.9	269.2	274.6	280.0	285.6	291.4	297.2	303.1
Dependable Capacity Payment, $m	1.989	2.029	2.070	2.111	2.153	2.196	2.240	2.285	2.331	2.378	2.425
Total Payment, $million	**5.162**	**5.247**	**5.333**	**5.421**	**5.511**	**5.602**	**5.696**	**5.791**	**5.888**	**5.987**	**6.087**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146
Non-Firm Winter Energy	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037
Energy Payment, $million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871
Added Winter Load, GWh	5.2	5.6	6.1	6.6	7.0	7.5	8.0	8.5	8.9	9.4
Added Load Rate [YUB price $0.19/kWh]	0.006	0.006	0.007	0.008	0.009	0.009	0.010	0.011	0.012	0.013
Added Load Rate Payment, $m	0.177	0.197	0.218	0.240	0.262	0.285	0.309	0.334	0.360	0.387
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5
Dependable Capacity Payment, $m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956
Total Payment, $million	**6.190**	**6.295**	**6.402**	**6.512**	**6.623**	**6.737**	**6.852**	**6.971**	**7.091**	**7.214**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.147	0.149	0.150	0.152	0.153	0.155	0.156	0.158	0.159	0.161
Non-Firm Winter Energy	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040	0.040	0.041
Energy Payment, $million	3.910	3.949	3.989	4.029	4.069	4.109	4.151	4.192	4.234	4.276
Added Winter Load, GWh	9.9	10.4	10.9	11.3	11.8	12.3	12.8	13.3	13.7	14.2
Added Load Rate [YUB price $0.19/kWh]	0.013	0.014	0.015	0.016	0.017	0.018	0.020	0.021	0.022	0.023
Added Load Rate Payment, $m	0.415	0.443	0.473	0.504	0.536	0.568	0.602	0.638	0.674	0.712
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	376.9	384.4	392.1	400.0	408.0	416.1	424.5	432.9	441.6	450.4
Dependable Capacity Payment, $m	3.015	3.076	3.137	3.200	3.264	3.329	3.396	3.464	3.533	3.604
Total Payment, $million	**7.340**	**7.468**	**7.599**	**7.732**	**7.868**	**8.007**	**8.149**	**8.293**	**8.441**	**8.592**

(b)

Please see the tables provided below. Please also see response to JM-YEC-1-16.

In addition to notes provided for tables in (a) above, the following are also noted with regard to the tables provided in this response:

- The non-industrial growth is assumed at the same rate as in question a) [0.12%/year after 2035].

- The added annual industrial load is assumed at 60 GWh/year for 2035-2044 [assume 42.6 GWh “winter” load that affects the Additional Payment].

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.132	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Non-Firm Winter Energy	0.072	0.073	0.073	0.074	0.075	0.076	0.076	0.077	0.078	0.079	0.080
Energy Payment, $million	3.725	3.762	3.800	3.838	3.876	3.915	3.954	3.993	4.033	4.074	4.114
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	200	204.0	208.1	212.2	216.5	220.8	225.2	229.7	234.3	239.0	243.8
Dependable Capacity Payment, $m	1.600	1.632	1.665	1.698	1.732	1.767	1.802	1.838	1.875	1.912	1.950
Total Payment, $million	**5.325**	**5.394**	**5.464**	**5.536**	**5.608**	**5.681**	**5.756**	**5.831**	**5.908**	**5.986**	**6.065**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.119	0.121	0.122	0.123	0.124	0.125	0.127	0.128	0.129	0.131	0.132
Non-Firm Winter Energy	0.030	0.030	0.031	0.031	0.031	0.032	0.032	0.032	0.033	0.033	0.033
Energy Payment, $million	3.173	3.204	3.236	3.269	3.302	3.335	3.368	3.402	3.436	3.470	3.505
Added Winter Load, GWh		43.1	43.5	44.0	44.5	44.9	45.4	45.9	46.3	46.8	4.7
Added Load Rate [YUB price $0.19/kWh]		0.039	0.041	0.042	0.043	0.045	0.046	0.047	0.049	0.050	0.005
Added Load Rate Payment, $m		1.214	1.252	1.291	1.330	1.371	1.413	1.456	1.501	1.546	0.158
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	248.7	253.6	258.7	263.9	269.2	274.6	280.0	285.6	291.4	297.2	303.1
Dependable Capacity Payment, $m	1.989	2.029	2.070	2.111	2.153	2.196	2.240	2.285	2.331	2.378	2.425
Total Payment, $million	**5.162**	**6.448**	**6.558**	**6.671**	**6.785**	**6.902**	**7.022**	**7.143**	**7.267**	**7.394**	**6.087**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146
Non-Firm Winter Energy	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037
Energy Payment, $million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871
Added Winter Load, GWh	5.2	5.6	6.1	6.6	7.0	7.5	8.0	8.5	8.9	9.4
Added Load Rate [YUB price $0.19/kWh]	0.006	0.006	0.007	0.008	0.009	0.009	0.010	0.011	0.012	0.013
Added Load Rate Payment, $m	0.177	0.197	0.218	0.240	0.262	0.285	0.309	0.334	0.360	0.387
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5
Dependable Capacity Payment, $m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956
Total Payment, $million	**6.190**	**6.295**	**6.402**	**6.512**	**6.623**	**6.737**	**6.852**	**6.971**	**7.091**	**7.214**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.147	0.149	0.150	0.152	0.153	0.155	0.156	0.158	0.159	0.161
Non-Firm Winter Energy	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040	0.040	0.041
Energy Payment, $million	3.910	3.949	3.989	4.029	4.069	4.109	4.151	4.192	4.234	4.276
Added Winter Load, GWh	9.9	10.4	10.9	11.3	11.8	12.3	12.8	13.3	13.7	14.2
Added Load Rate [YUB price $0.19/kWh]	0.013	0.014	0.015	0.016	0.017	0.018	0.020	0.021	0.022	0.023
Added Load Rate Payment, $m	0.415	0.443	0.473	0.504	0.536	0.568	0.602	0.638	0.674	0.712
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	376.9	384.4	392.1	400.0	408.0	416.1	424.5	432.9	441.6	450.4
Dependable Capacity Payment, $m	3.015	3.076	3.137	3.200	3.264	3.329	3.396	3.464	3.533	3.604
Total Payment, $million	**7.340**	**7.468**	**7.599**	**7.732**	**7.868**	**8.007**	**8.149**	**8.293**	**8.441**	**8.592**

In the above examples the added winter load remains below the max 68 GWh. As illustrated in example provided in response to JM-YEC-1-16, the added winter load for the EPA purposes is capped at 68 GWh, therefore, if the added winter load is higher than 68 GWh then 68 GWh would be used as added winter load.

(d)

The EPA energy pricing is not based on LCOE, but on LTA thermal displacement benefits. Therefore, the requested information is not available.

TOPIC: **Section 3 Overview of the Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page 11 bottom: "If YEC requests delivery of energy during the summer months (June-August) YEC pays a 'discounted' price equal to 50% of the last approved YUB blended fuel price." And**

Page 14 Table 3-1

QUESTION:

a) If the 2021 YEC GRA suggested blended fuel price is approved by the Yukon Utilities Board (YUB) would the approximate summer energy price be about $0.095 per kWh in 2024?

b) This is a higher rate than for winter non-firm winter energy (in 2024), please explain the rationale for this apparent higher pricing in summer.

c) When a pumped hydro storage facility is built on the YIS would this not discourage the use of what might otherwise be a potential benefit?

ANSWER:

(a)

The 2021 GRA blended fuel price is $0.1837/kWh (90% of LNG at $0.1814, 10% of diesel at $0.2051).

50% of this 2021 GRA blended fuel price equals $0.0918/kWh. This would be the summer fuel price at times when the last approved YUB blend fuel price is $0.1837/kWh.

(b)

The EPA treats any summer energy deliveries as a separate transaction based on the agreed upon price. This reflects the situation where EPA prices adopted for winter deliveries reflect the same forecast displaced thermal generation with or without summer

Atlin generation, i.e., based on current forecasts the summer Atlin energy has no value. If summer energy had been included in the EPA committed deliveries the EPA price would have been reduced as needed to reflect that the added deliveries added nothing to forecast displaced thermal generation.

The EPA summer price addresses a potential, if not currently forecast, situation where the YIS substantial summer renewable energy surplus forecast from YEC's summer hydro plus all SOP IPP summer generation is exhausted, i.e., a situation when YEC would be required to rely on summer thermal generation. In this specific situation, the EPA provides opportunity to access Atlin renewable energy at 50% of the then YUB approved blend fuel thermal price.

(c)

No. If pumped storage is built and Skagway summer sales are also enabled, the summer renewable generation would be materially reduced. Access to Atlin energy at 50% of the then relevant thermal fuel cost would still encourage use of this renewable resource.

TOPIC: **Section 4 Aspects of the Agreement for Board Review**

REFERENCE:

PREAMBLE: **Page 17: "Winter vs Summer Shifts", and**

Page 21: "…The result is surplus renewable energy generation during summer (which cannot be used or sold to other jurisdictions) …"

QUESTION:

a) In YEC's 2024 forecast used for this EPA, what time or times of day is surplus renewable energy available during the Summer Period and during the Winter Period, if any?

b) How many SCADA controlled secondary sales customers does YEC presently have? Can they be turned on and off in relatively short time blocks of say 2 hours for example? If not, what are the practical on and off time blocks?

c) What level of secondary energy sales do these represent in each of the months of June, July, August, and September?

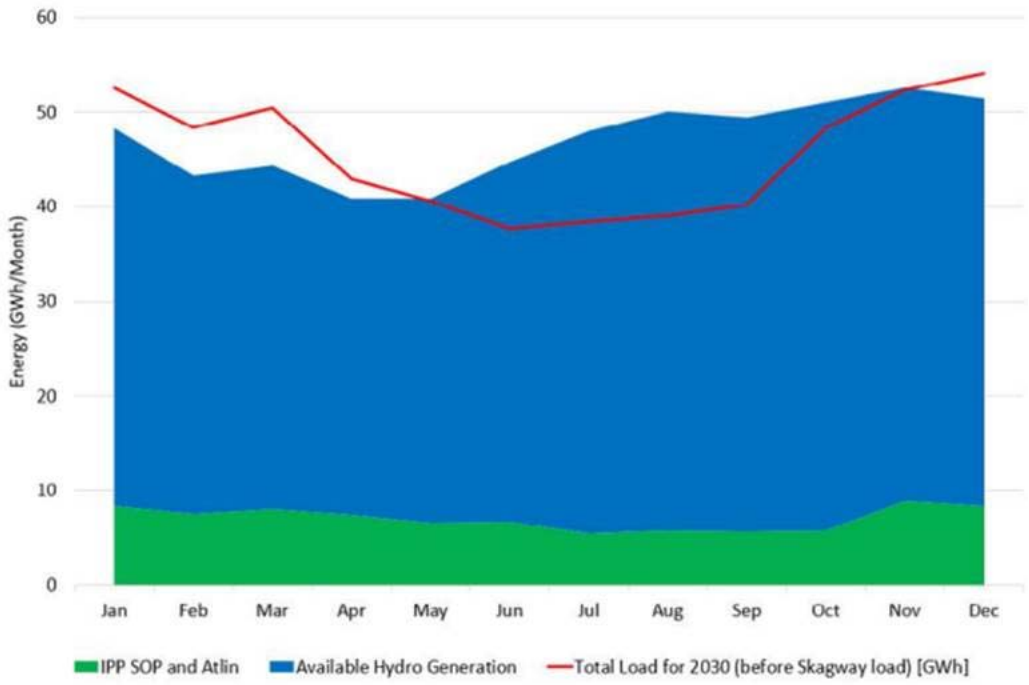
d) Has YEC considered marketing secondary sales to other customers to increase secondary sales volumes and reduce greenhouse gas (GHG) emissions in line with the Yukon government's Our Clean Future climate change strategy?

ANSWER:

(a)

Yukon Energy does not have any surplus renewable energy in the winter months (November through April). Surplus renewable energy is typically available June through October. The figure below illustrates the expected renewable surplus on a monthly basis (Figure 15 from the 10-year Renewable Electricity Plan – see YUB-YEC-1-32, Attachment 1).

Figure 15: Monthly Renewable Supply vs Demand (2030)



The hourly/weekly/daily timing of surplus renewable energy is highly variable as it depends on the output of intermittent renewable resources. In July and August, it is expected almost all energy generation from the wind and solar resources in the Standing Offer Program will be surplus given the typical summer load profile.

(b)

There are six SCADA connected secondary sales customers. The controls are very simple, turning the secondary energy sales (SES) availability on or off. The controls are issued real-time and are immediate. The controls provide a start permissive to the customer. If the customers system is in service and available the transition to SES occurs within minutes.

(c)

Please see the table below in 2021.

	Secondary Sales (KWh)
JUN	1,966,085
JUL	435,150
AUG	361,750
SEP	274,820

(d)

The primary use of secondary sales is building heat**,** requiring the customers to have a primary heat source as well as an electric heat source.

SES is available when there is no thermal generation (diesel/natural gas) online and there is excess hydro generation available. This generation dispatch is typically available 5-6 months of the year. The system continues to experience load growth which reduces the availability of SES. This will continue until more renewable energy is brought online.

YEC does not promote adding more SES to the system due to the forecasted reduction in availability to existing and potential new customers. There is no guarantee of availability. There is a significant cost to customers to access SES. Maintaining their primary heat source and the addition of a SES electric heat source and controls.

TOPIC: **Section 4 Aspects of the Agreement for Board Review**

REFERENCE:

PREAMBLE: **Page 18 second paragraph: "… Without new resources, this shortfall and the requirement for diesel rentals is forecast to increase significantly in subsequent years due to peak load growth and the retirement of existing resources.[22, 23]"**

QUESTION:

a) Is YEC be considering uprates of WH1, WH3, AH1, AH2, and Mayo A hydro units prior to 2030? Please explain.

b) Does YEC plan to replace retiring thermal generation resources?

ANSWER:

(a)

No. The resource planning exercises conducted to date have not identified these uprates to be economic options before 2030 with current information and expected capacity output resulting from the projects.

(b)

Yes. Yukon Energy's current resource plan includes like-for-like replacement of any existing thermal resources expected to retire.

TOPIC: **Section 4 Aspects of the Agreement for Board Review**

REFERENCE:

PREAMBLE: **Page 20 Figure 4-1**

QUESTION:

a) What was this winter's (2021-2022) peak demand?

b) What was the non-industrial portion of this peak demand?

c) This Figure 4-1 shows the significant dependable capacity impact of the proposed Moon Lake pumped hydro storage project targeted to come on-stream in 2028, about 4 years into the 40-year EPA. The Moon Lake project would add some new energy (about 10 GWh per year) to the YIS and use surplus summer energy to displace winter thermal energy. Please explain how the price calculations required by the EPA can or will be made for the period following the proposed development of Moon Lake and / or another such pumped hydro facility.

d) Please explain how YEC will ensure that the ratepayer interests will be protected in all eventualities.

ANSWER:

(a) and (b)

The peak for 2021/22 winter was at 114.67 MW recorded on January 6, 2022 [excluding AEY's Fish Lake - with Fish Lake the total YIS peak was 116 MW]. The 114.67 MW peak includes 101.08 MW non-industrial and 13.59 MW industrial peak.

(c) and (d)

As reviewed in the Submission, EPA pricing determinations for winter energy and dependable capacity did not assume or address the Moon Lake project, and these EPA prices will not change if and when Moon Lake and/or another such pumped storage is developed.

Ratepayer interests are being protected by the EPA approach for the Atlin project, to enable this opportunity (subject to THELP development plans and funding as required) to secure renewable dependable capacity and energy before the end of 2024 at prices that mirror expected thermal generation costs otherwise required. Moon Lake and/or any other pumped storage options remain today at pre-feasibility stages of development with a requirement for material federal grant funding under any potential development scenario. In assessing the benefits of Moon Lake pumped storage to determine its feasibility, it will be necessary to take into account at that time the thermal displacement benefits from the Atlin EPA as well as SOP IPPs in order to determine the net benefits offered for YEC and ratepayers from this additional project.

TOPIC: **Section 4 Aspects of the Agreement for Board Review**

REFERENCE:

PREAMBLE: **Page 22 footnote 32: "The thermal generation displacement from IPPs can be constrained due to seasonality of IPP generation options, especially solar projects and run-of-river hydro projects, which will have materially lower winter generation output." And**

Page 26 last two bullets discussing IPP SOP renewable energy projects.

QUESTION:

a) What incentives has YEC put in place to encourage materially higher winter generation from IPP SOP projects?

b) Since wind power generation produces predominantly winter energy, what specifically has YEC done to encourage cost effective wind IPP projects?

ANSWER:

(a) and (b)

YEC does not incentivize or encourage certain generation technologies under the program. The program rules are developed jointly by YEC, AEY and Yukon Government; the utility does not have the ability to prioritize one qualifying technology over the other by these rules.

TOPIC: **Section 4 Aspects of the Agreement for Board Review**

REFERENCE:

PREAMBLE: **Page 23 second bullet**

QUESTION:

a) Please provide the electrical energy forecast that indicated relatively stable non-industrial loads for the last 30-year period of the EPA from 2034 to 2065. What is the annual non-industrial electrical energy load growth rate through the 40-year EPA and through the last 30 years in particular?

b) Yukon has been experiencing significant population growth, experiencing the increasing use of electric heat for residential dwellings including switching to electric heat from fossil fuels, and Yukoners are being encouraged to switch to electric vehicles. Using only a low growth forecast and not considering the possibility of higher growth rates due to these factors appears imprudent when considering long-term ratepayer impacts. Please explain.

c) Please prepare an analysis using an annual electrical energy growth rate of 1.5% per year for this 30-year period from 2035 to 2065 inclusive and assume that the YUB Price will increase at 2% per year from $0.19 per kWh in 2024 in order to show what the ratepayer impact will be compared to assumptions in this submission. As part of the analysis please prepare a table of 40 years of energy costs such as those provided in answer to JM-YEC-1-10 for comparison purposes.

ANSWER:

(a)

The referenced quote is addressing forecast energy load on the YIS that will determine opportunities for thermal energy displacement benefits due to the EPA.

YEC's available long-term forecasts are those provided in the 10-Year Renewable Electricity Plan (see YUB-YEC-1-32, Attachment 1; summarized in Submission, Figure 4-1 and Table 4-1).

YEC's available forecasts show only non-industrial load after 2034, and also show non-industrial load being expected to stop material growth by about 2030, becoming relatively stable at about 0.5% per year after including provision for new EV load growth[1]. The available forecasts showing this expected non-industrial load do not extend beyond about 2041.

(b)

The Atlin EPA energy price is based on the benefits forecast from displaced thermal generation. This EPA price is reduced after 2034 to reflect forecast YIS loads without industrial customers. For the purpose of setting this EPA price, which locks in ratepayer costs for the EPA after 2034, it is prudent and reasonable to utilize these available forecasts. The rate impact risk for ratepayers is that actual loads will be less than forecast, resulting in the EPA price being higher than the actual displaced thermal benefits. Ratepayers will benefit if actual loads are higher than this forecast after 2034 – and THELP will share in these benefits through the Additional Payment provisions of the EPA.

(c)

Please see Table 1 for requested information which assumes 1.5%/year growth for non-industrial winter load after 2035 (EPA assumed 388 GWh 2035 non-industrial winter load) and the CPI at 2% for energy and capacity rate calculations as well as the YUB price at $0.19/kWh [2024$] also with inflation at 2%/year. Please note that the added winter load for the EPA purposes is capped at 68 GWh, therefore, the years 2046 and thereafter only show added winter load at 68 GWh for the purpose of the Additional Payment forecast.

Table 1 shows the impact on the EPA payments – it does not show the impact on overall ratepayer costs from the changed assumptions. Assessments of overall ratepayer costs would require addressing forecast new resources to deal with the added load, and the mix of IPP versus YEC resources – which is beyond what YEC can provide at this time.

[1] The 10-Year Renewable Electricity Plan load forecast which was used for the EPA pricing analysis assumes approximately 6,000 EVs by 2030 which adds about 26 GWh/year load to YIS.

It is also noted that Table 1 assumes YUB Price for thermal escalating at 2% per year throughout, leading to future thermal fuel price assumptions higher than may be prudent to assume.

Table 1: Annual Payments with 2% CPI and 1.5% Non-Industrial Load Growth

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.132	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Non-Firm Winter Energy	0.072	0.073	0.073	0.074	0.075	0.076	0.076	0.077	0.078	0.079	0.080
Energy Payment, $million	3.725	3.762	3.800	3.838	3.876	3.915	3.954	3.993	4.033	4.074	4.114
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	200	204.0	208.1	212.2	216.5	220.8	225.2	229.7	234.3	239.0	243.8
Dependable Capacity Payment, $m	1.600	1.632	1.665	1.698	1.732	1.767	1.802	1.838	1.875	1.912	1.950
Total Payment, $million	**5.325**	**5.394**	**5.464**	**5.536**	**5.608**	**5.681**	**5.756**	**5.831**	**5.908**	**5.986**	**6.065**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh											
Firm Winter Energy	0.119	0.121	0.122	0.123	0.124	0.125	0.127	0.128	0.129	0.131	0.132
Non-Firm Winter Energy	0.030	0.030	0.031	0.031	0.031	0.032	0.032	0.032	0.033	0.033	0.033
Energy Payment, $million	3.173	3.204	3.236	3.269	3.302	3.335	3.368	3.402	3.436	3.470	3.505
Added Winter Load, GWh		5.8	11.7	17.7	23.8	30.0	36.3	42.6	49.1	55.6	62.3
Added Load Rate [YUB price $0.19/kWh]		0.005	0.011	0.017	0.023	0.030	0.037	0.044	0.052	0.060	0.068
Added Load Rate Payment, $m		0.164	0.337	0.520	0.712	0.915	1.129	1.353	1.589	1.838	2.099
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	248.7	253.6	258.7	263.9	269.2	274.6	280.0	285.6	291.4	297.2	303.1
Dependable Capacity Payment, $m	1.989	2.029	2.070	2.111	2.153	2.196	2.240	2.285	2.331	2.378	2.425
Total Payment, $million	**5.162**	**5.398**	**5.644**	**5.900**	**6.167**	**6.446**	**6.737**	**7.040**	**7.356**	**7.685**	**8.028**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146
Non-Firm Winter Energy	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037
Energy Payment, $million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871
Added Winter Load, GWh	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Added Load Rate [YUB price $0.19/kWh]	0.076	0.077	0.079	0.081	0.082	0.084	0.086	0.087	0.089	0.091
Added Load Rate Payment, $m	2.337	2.384	2.431	2.480	2.530	2.580	2.632	2.684	2.738	2.793
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5
Dependable Capacity Payment, $m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956
Total Payment, $million	**8.350**	**8.482**	**8.616**	**8.752**	**8.891**	**9.031**	**9.175**	**9.321**	**9.469**	**9.620**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
Firm Winter Energy	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*	*25.2*
Non-Firm Winter Energy	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*	*5.6*
Energy Price, $/kWh										
Firm Winter Energy	0.147	0.149	0.150	0.152	0.153	0.155	0.156	0.158	0.159	0.161
Non-Firm Winter Energy	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040	0.040	0.041
Energy Payment, $million	3.910	3.949	3.989	4.029	4.069	4.109	4.151	4.192	4.234	4.276
Added Winter Load, GWh	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
Added Load Rate [YUB price $0.19/kWh]	0.093	0.094	0.096	0.098	0.100	0.102	0.104	0.106	0.109	0.111
Added Load Rate Payment, $m	2.849	2.906	2.964	3.023	3.084	3.145	3.208	3.272	3.338	3.405
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment $/kW	376.9	384.4	392.1	400.0	408.0	416.1	424.5	432.9	441.6	450.4
Dependable Capacity Payment, $m	3.015	3.076	3.137	3.200	3.264	3.329	3.396	3.464	3.533	3.604
Total Payment, $million	**9.774**	**9.930**	**10.090**	**10.251**	**10.416**	**10.584**	**10.754**	**10.928**	**11.105**	**11.284**

TOPIC: **Appendix A: Supporting Figures and Tables**

REFERENCE:

PREAMBLE: **Page A-3 Table A3-1, and**

Page 14, Table 3-1

QUESTION:

a) In the 2024 load forecast portion of the table the non-industrial load is listed as 453.3 GWh, the industrial load as 74.6 GWh, and the total load at 527.9 GWh. The YEC 2021 GRA forecast shows an industrial load of about 112.7 GWh (102.9 GWh industrial sales + 9% load losses), non-industrial load of about 427.6 GWh (by difference) and a total load of 538.7 GWh. Please explain the apparent discrepancy between the 2024 forecast and 2021 actual numbers.

b) In the 2024 forecast YEC adds forecasted increased generation of 10.2 GWh for hydro uprates and 39.9 GWh for "IPPs + incremental microgen". Since microgeneration is by definition behind the customers' meters manifesting itself as reduced load, how can such a number be determined or measured when it is a mix of measured and non-measured supplies?

c) The non-industrial load is forecast to be 483.1 GWh per year in 2035 (Table A3-5), please explain the calculation that resulted in a YIS Winter Period generation of 388 GWh per year used in Table 3-1.

ANSWER:

(a)

YEC would like to clarify that the referenced 2021 GRA numbers are forecasts for 2021, not actuals.

The load forecast for 2024 that was used for the EPA analysis is based on 10-Year Renewable Plan that was developed in response to Yukon government's draft Our Clean Future: A Yukon strategy for climate change, energy and a green economy and reflects

ongoing economic growth of the Territory and increased demand for renewable energy from the policies and actions outlined in the strategy, including increased demand for EVs. The 10-Year Plan forecast included a 1.5%/year growth in non-industrial load between 2021 and 2024.

The load forecast for 2021 was refined/updated for the 2021 GRA based on updated information available at the time of preparation of the GRA application. The annual average increase in non-industrial load from 2021 GRA forecast [427 GWh] and 2024 forecast [453 GWh] is about 2%/year which reflects expected growth in electricity demand based on policies and actions outlined in the strategy, including increased demand for EVs.

The actual sales in 2021 were lower compared to the 2021 GRA load forecast due to lower industrial load [industrial load with losses at 98.6 GWh compared to 112 GWh in the GRA forecast]. The actual non-industrial load was close to the GRA forecast [at 428.7 GWh with losses compared to 426.7 GWh GRA forecast].

(b)

The microgeneration is not a supply option for YIS per se, however, it results in reduction in overall load on YIS. Although, the actual microgeneration numbers are embedded in actual generation numbers [i.e., the actual generation numbers reflect reduced load due to microgeneration load generated by customers], in the 10-Year Renewable Electricity Plan YEC has included micro-generation-sourced energy in its committed resource assumptions and for forecasting purposes the non-industrial load was prepared at gross level. Therefore, the incremental microgeneration was added separately as a reduction in load. This way of presenting the information does not impact the LTA thermal displacement estimates.

(c)

Please see Table 2 in response to JM-YEC-1-6. The 388 GWh “winter” generation reflects the sum of total generation for Jan-May and Sep-Dec as per Table 2.

TOPIC: **Appendix A: Supporting Figures and Tables**

REFERENCE:

PREAMBLE: **Pages A-5 Figure A1, and page A-6 Figure A2**

QUESTION:

a) In the top half of each of these Figures there are numbers for energy deliveries to Jakes Corner and LTA thermal displacement. By difference we can calculate in Figure A1 a "non-thermal displacement" of 11.2 GWh and in Figure A2 of 15.8 GWh. Do these purchases result directly in an equivalent amount of "spilled" energy on the YIS system? Please explain what benefits the purchase of these amounts of energy have for Yukoners.

b) In the lower half of each of these figures the thermal displacement by water storage savings is shown. Do these savings include the potential longer-term benefits of having fuller reservoirs in Yukon should a significant drought occur as well as the season to season savings?

c) Are there any benefits other than thermal displacement, for example environmental, that may be experienced from the timing of the storage?

ANSWER:

(a) and (b)

The LTA thermal displacement estimates in Appendix A are based on YIS water conditions over 38 water years, and include any related hydro storage benefits that subsequently enable thermal displacements. Atlin LTA deliveries that do not yield estimated LTA thermal displacement benefits are assumed to reflect added "spilled" energy on the YIS. See also responses to YUB-YEC-1-11 and YUB-YEC-1-12.

(c)

YEC has focused on thermal displacement ratepayer cost impacts and related environmental benefits, e.g., reduced GHGs. Other benefits are not identified.

TOPIC: **Appendix A: Supporting Figures and Tables**

REFERENCE:

PREAMBLE: **Page A-8 Table A4-2**

QUESTION:

a) Please provide the section 3 calculation of Additional Payment at the end of the Winter Period for the year 2035 with the non-industrial load at 483.1 GWh as forecast for 2034 (page A-3 Table A3-1). Assume that the dependable excess capacity payment account is nil.

b) Please provide this calculation for year 2045 with YEC's forecasted load growth and a 2% per year inflation rate on YUB Price.

c) Please provide this calculation for the year 2055 with the same assumptions as in (b) and (a) above.

d) Please provide this calculation for the year 2064 with the same assumptions as in (b) and (a) above.

e) If the above requested information is embedded in response to JM-YEC-1-10, please just reference that response.

ANSWER:

(a) through (e)

Please see response to JM-YEC-1-10.

TOPIC: **Appendix B Summary of KEY EPA Terms and Conditions**

REFERENCE:

PREAMBLE: **Page B-3: "YEC's winter peak non-industrial load forecast for assessing N-1 dependable capacity requirements assumes -38°C, with approximately 8 MW load being added by the average daily temperature drop below -30°C."**

QUESTION:

a) Please confirm that the -38°C referenced is, as the -30°C is stated to be, an average daily temperature.

b) Is the stated 8 MW load increase an increase in peak load or an increase in the average daily load?

c) If peak load increase is different than the average daily load increase, what is the difference between these numbers over this temperature range?

ANSWER:

(a)

Confirmed.

(b)

No, the temperature drop from -30°C to -38°C is estimated to add about 8 MW to the peak load, not average daily load.

(c)

The analyses were done to check the impact of the temperature to the non-industrial peak load which is used in the N-1 assessment. No assessments were done for the average daily load, therefore, the requested information is not available.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-7 clause 2.1 (d) (ii)**

QUESTION:

a) Please provide the budgeted costs for the AEY System Upgrades.

b) Please provide the YEC upgrade costs.

ANSWER:

(a) and (b)

Please see response YUB-YEC-1-9(a).

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-7 clause 2.1 (d) (v)**

QUESTION:

a) Page 1 of the EPA would appear to be page A1-2 of this submission. Please confirm that the date referenced is found on the cover of the EPA (no page number) and page 4 of the EPA (page A1-5 of submission) which is January 14, 2022.

ANSWER:

(a)

Confirmed.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-8 clause 2.1 (d) (vii)**

QUESTION:

a) Please confirm that the Seller has obtained the consents specified by February 28.

ANSWER:

(a)

Not confirmed. Please see response to CW-YEC-1-7 – the date for satisfaction of clause 2.1(d)(vii) has been extended to May 31, 2022.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-8 clause 2.1 (d) (ix)**

QUESTION:

a) Please confirm that YEC has entered into an implementation agreement with AEY and please provide a copy of that agreement.

ANSWER:

(a)

Please see response to CW-YEC-1-7. The implementation agreement has not been completed and the date for satisfaction of clause 2.1(d)(ix) has been extended to March 31, 2022.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-8 clause 2.3**

QUESTION:

a) Please indicate whether the parties intend the new agreement to take effect immediately upon completion of the renewal or replacement agreement or at the termination of the EPA at the end of May 2065.

ANSWER:

(a)

As noted in section 2.3 of the EPA, the renewal or replacement of the EPA would not be effective until the Parties have executed and delivered a legally binding agreement renewing or replacing the EPA. The objective specified is that this would occur on the latter of the 35th anniversary of the Phase One Seller's COD or the Phase Two Sellers COD – however, this could potentially occur after the referenced 35th anniversary so long as it is before the end of the Term for the current EPA. These provisions do not specifically address whether a new EPA would replace the current EPA before the end of its Term, or simply commence to be effective after the end of current EPA Term.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-10 clause 3.6 (a) (ii)**

QUESTION:

a) Please provide a copy of the Buyer-AEY System Interconnection Report.

ANSWER:

(a)

The reference should be “Buyer-AEY System Interconnection Study Report”. Please see response to JM-YEC-1-8(a).

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-18 (top) clause 6.5: "…Buyer will give Seller notice…when it provides its monthly invoices under section 8.8."**

QUESTION:

a) Section (clause) 8.8 does not refer to "invoices"; should clause 6.5 specify "Notice of the Meter record" as used in clause 8.8 rather than invoice?

ANSWER:

(a)

The wording would be clearer in section 6.5 without use of the word "invoices". However, the wording still is clear as to what is required of Buyer regarding giving Notice to Seller of what in effect is Monthly Constraint Energy:

1. There is clear reference in section 6.5 to Buyer providing this information concurrently when it provides monthly information to Seller under section 8.8.

2. Section "a" is the only part of Section 8.8 where Buyer provides information to Seller on a monthly basis.

3. Section 8.8 also clearly requires that Buyer information provided to Seller each month include "Buyer's estimate for any Monthly Constraint Energy for the preceding month".

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-20 clause 8.3 (a) (iii) "Capacity Shortfalls"**

QUESTION:

a) This clause appears to say that Seller will be paid for a minimum of 50% of the Actual Dependable Plant Capacity Committed in a particular year, is this the correct interpretation? If not please clarify.

b) Is the Actual Dependable Plant Capacity Committed 8 MW to 8.5 MW or can it be different? Please explain.

ANSWER:

(a)

Yes, the clause caps the Capacity Shortfall in any Peak Winter Period at 50% of Actual Dependable Plant Capacity Committed, which in turn depends on the annual Dependable Plant Capacity Test.

(b)

Actual Dependable Plant Capacity Committed can be different than being between 8 and 8.5 MW, and could be as low as zero under some circumstances.

Actual Dependable Plant Capacity Committed is in effect the capacity that was paid for during a Peak Winter Period (PWP). It is limited for each PWP by the Dependable Plant Capacity Committed or DPCC, as used to determine Dependable Capacity Payments that were made for the PWP. Dependable Plant Capacity Committed is:

1. Dependable Plant Capacity in kW up to a maximum of 8,500 kW that is confirmed at the final commercial operation date [COD] for Seller's Plant [therefore, the 8.5 MW is a cap, but this result during COD could be less than 8 MW], less

2. The reduction for a PWP as provided for in a Dependable Plant Capacity Test under Section 5.5 or Notice under Section 6.2 [these reductions could in principle reduce the DPCC to well below 8 MW, including to zero].

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-22 clause 8.8 (e)**

QUESTION:

a) The last line appears to have something missing or a typo, should the word “who” come after Party?

ANSWER:

(a)

Correct.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-24 clause 9.1 last sentence**

QUESTION:

a) There appears to be something missing after "…a "material default"…".

ANSWER:

(a)

Section 9.1 includes a typo and the final sentence should not include the word "for".

The final sentence should read:

> Any failure by Seller to exercise such commercially reasonable efforts under this Section 9.1 is a "material default" under this EPA, and Buyer may terminate this EPA under Section 14.1(g)."

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-52 clause 1.69: "in Year 2035 and for each subsequent Year $0.107/KWh*Half Inflation Index."**

QUESTION:

a) Please clarify whether the "Half Inflation Index" begins in year 2024 or 2035.

ANSWER:

(a)

The Half Inflation Index is referenced to the CPI Index value in December 2023. The calculation for each calendar year of 50% uses the CPI Index value for December prior to the calendar year, e.g., for year 2024, CPI Index value would be for December 2023 (and there would therefore be no escalation).

The referenced Firm Winter Energy Price provides, for 2035 and each subsequent Year, a price of $0.107/kWh escalated by the Half Inflation Index, e.g., this price for 2035 would be escalated based on CPI Index value for December 2034 relative to the Index value for December 2023.

TOPIC: **Attachment A Electricity Purchase Agreement**

REFERENCE:

PREAMBLE: **Page A1-66 EXHIBIT B-1**

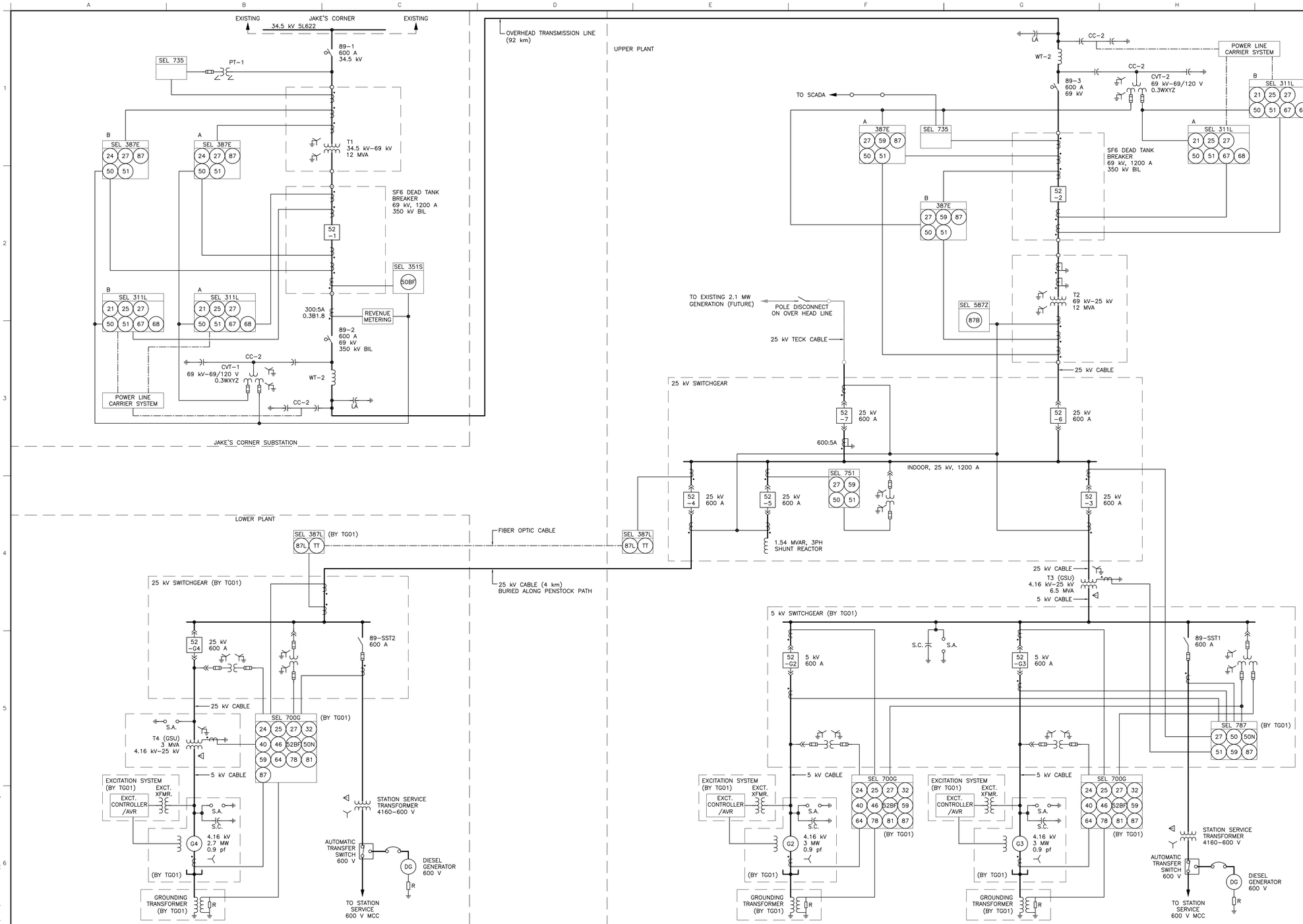
QUESTION:

a) Please provide a higher resolution digital copy of this exhibit so that the content is legible when enlarged.

ANSWER:

(a)

Please see Attachment 1 to this response.



ALL DIMENSIONS AND ELEVATIONS ARE IN METERS, UNLESS OTHERWISE NOTED

ISSUE	REV.		DATE	DRWN	DSGN	CHK	REVW	APPR
1	PA	ISSUE FOR TG01 REP	SEP-02-21	VW	YP	–	PM	

–	–	–	–	–	–
REV.	CIVIL	ELEC.	MECH.	GEO.	CONSTR.

INTERDISCIPLINE REVIEW

PREPARED FOR:

DRAWN: VW	DESIGN: YP
CHECK:	REVIEW: PM
SCALE: AS NOTED	DATE: AUG 28, 2021

ATLIN EXPANSION PROJECT

OVERALL
SINGLE LINE DIAGRAM

SNC·LAVALIN

SNC-LAVALIN INC.
745 Thurlow St.
Vancouver, B.C. Canada

679656-
0000-47D2-0002 | PA

SL DRAWING NUMBER | REV

SL CAD: *.DWG

DATE: 2021/09/02 - 2:47pm
PATH: X:\679656 - Atlin Expansion Project\DWG\V47 - Electrical\\679656-0000-47D2-0002.dwg

NATHANIEL YEE
(NY)

REFERENCE: **The FAQ on the THELP web page for the Project notes that "The Atlin Hydro Expansion Project will only generate power for the Yukon once the power needs of Atlin have been met. The power needs of Atlin are the first priority when it comes to the water resources of Surprise Lake."**

QUESTION:

a) Is this consistent with YEC's understanding of the agreement? If not, please provide specifics.

ANSWER:

(a)

YEC's understanding on this matter is as follows:

1. The Atlin Hydro Expansion Project is a separate facility from the Existing Plant, with all Energy from the Project to be exclusively provided only to YEC as provided in Section 7.1 of the EPA.

2. The expected water availability from Surprise Lake is sufficient to meet expected power needs of Atlin (as supplied from the Existing Plant) as well as provide 8 to 8.5 MW of dependable capacity to YEC during the Peak Winter Period (see Appendix A to the Submission, Tables A1 and A2).

3. THELP will cause Xeitl Limited Partnership ("XLP"), by its general partner Atlin Power Limited ("APL"), to not amend, modify, or make any changes to the Existing Plant which would have a material adverse effect on Seller's ability to deliver and Buyer's ability to receive during each Peak Winter Period the minimum energy deliveries as set out in Section 7.2(a) of the EPA.

4. The EPA does not have any specific provision stating that the Atlin Hydro Expansion Project will only generate power for the Yukon once the power needs of Atlin have been met.

Please see response to YUB-YEC-1-4 for additional analysis and information on the ability of the Project and the Existing Plant to be operated simultaneously at full capacity for extended periods during the Peak Winter Period.

TOPIC:

REFERENCE: **In the public presentation on 11-Feb, the slide listing capacities had in very large print "Eliminates 4 Rental Diesel Engines Each Winter."**

PREAMBLE:

QUESTION:

a) When the Project comes online, does YEC actually expect to have four fewer rentals than are currently installed, or was this just implied to sell the Project?

b) How many rental diesels does YEC expect to have each season from 2022-2035? On pages 18 and 19, scenarios involving 16, 24 and 35 rental diesels are mentioned, along with the text "the requirement for diesel rentals is forecast to increase significantly..." Please provide this forecast (rental diesel requirement by year) for 2022-2035.

ANSWER:

(a) and (b)

Please see response to YUB-YEC-1-13(c) for available forecasts of diesel rental requirements with and without the Project, focusing on winter 2024/25 and 2030/31. This information indicates that the EPA prior to in-service of Moon Lake Pumped Storage will reduce diesel rentals by 5 units (assuming each unit capacity = 1.8 MW).

TOPIC:

REFERENCE: Page A-3. Table A3-1.

PREAMBLE:

QUESTION:

a) Is it realistic to forecast and expect industrial load to be zero? No more industry in Yukon? Please explain this scenario.

ANSWER:

(a)

Yes. This is a prudent scenario when there are no firm forecasts for any specific planned and committed industrial load. This scenario occurred after closure of the Faro Mine until the Minto project was developed and connected with the Phase 1 of the Carmacks Stewart Transmission Project.

In the context of the Atlin EPA pricing, this scenario is particularly prudent when setting fixed energy prices intended to reflect forecast displaced thermal fuel generation costs that are dependent on forecast grid loads. In the event that actual loads are lower than forecast, ratepayers will incur net added costs relative to the thermal option to the EPA. In the event that actual loads are higher than forecast, ratepayers will benefit from lower added costs relative to the thermal option to the EPA and THELP will share in these benefits with YEC. In this way, YEC has structured this agreement to provide the highest possibility of a net benefit to Yukon ratepayers.

TOPIC:

REFERENCE: **Page A-3. Table A3-1 provides Forecast 12-month Annual Grid Load for 2024 and 2035.**

PREAMBLE:

QUESTION:

a) The 2021 GRA had a forecast total grid load of 538.7GWh. Is it realistic to expect 2024 and 2035 to be lower? Please explain.

b) Please provide the forecast annual grid load for all years from 2021 to 2035.

ANSWER:

(a)

Yes. The annual average increase in non-industrial load from 2021 GRA forecast [427 GWh] and 2024 forecast [453 GWh] is about 2%/year which reflects expected growth in electricity demand based on policies and actions outlined in the strategy, including increased demand for EVs. The lower loads for 2024 [528 GWh] and 2035 [483 GWh] when compared to the 2021 GRA load at 539 GWh are due to forecast changes in industrial loads. The 2021 GRA forecast includes 112 GWh industrial load [with losses], while 2024 forecast includes 75 GWh industrial load and for 2035 no industrial load was forecast in the 10 Year Renewable Electricity Plan.

Please also see the response to JM-YEC-1-17(a).

(b)

Please see the table below for the requested information. The load for 2021 is based on 2021 GRA; 2022-2035 years are based on 10-Year Renewable Electricity Plan.

The actual sales in 2021 were lower compared to the 2021 GRA load forecast due to lower industrial load [industrial load with losses at 98.6 GWh compared to 112 GWh in the GRA

forecast]. The actual non-industrial load was close to the GRA forecast [at 428.7 GWh with losses compared to the 426.7 GWh GRA forecast].

	Total Load before IPPs and Microgen, GWh
2021	538.7
2022	541.3
2023	521.7
2024	527.9
2025	534.4
2026	541.3
2027	546.8
2028	556.8
2029	567.5
2030	538.7
2031	528.4
2032	516.9
2033	514.7
2034	514.8
2035	483.1

TOPIC:

REFERENCE: Page 18, note 22.

PREAMBLE:

QUESTION:

a) Correction: Dependable capacity would actually be reduced by 5.0MW and not 5.2MW, as FD1 has been derated to 2.8MW. Please confirm.

ANSWER:

(a)

Not confirmed.

In response to NY-YEC-2-1 in YEC's 2021 GRA, YEC concluded that the FD1 unit could be run up to 2.4 MW while in remote mode without significant risk of an over-heating shutdown. This is a reduction of 0.6 MW from the dependable capacity assumed in the 10-Year Renewable Electricity Plan. Therefore, the reduction in dependable capacity would be 4.6 MW. Please see response to NY-YEC-1-6 for corrected table.

TOPIC:

REFERENCE:

PREAMBLE: Page 20 Table 4-1. Similar to above, YEC dependable thermal capacity is overstated due to derating of FD1. 2021/22 and 2022/23 YEC dependable thermal capacity is actually 35,850.

Other years may also be affected. Corresponding capacity shortfalls are also incorrectly stated.

QUESTION:

a) Please provide updated Table 4-1 reflecting correct existing dependable capacity.

b) Correction Page 18: N-1 Capacity shortfall is actually 26.6MW, as this number came from Table 4-1. Please confirm.

ANSWER:

(a) and (b)

In response to NY-YEC-2-1 in YEC's 2021 GRA, YEC concluded that the FD1 unit could be run up to 2.4 MW while in remote mode without significant risk of an over-heating shutdown. This is a reduction of 0.6 MW from the dependable capacity assumed in the 10-Year Renewable Electricity Plan. Please see revised version of Table 4-1 below.

Based on the revised table the capacity shortfall for 2021/22 is about 27 MW (compared with about 26.4 MW in the Submission Table 4-1).

Table 4-1 Revised: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (kW)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Non-industrial Peak	**104,102**	**107,372**	**110,546**	**113,952**	**117,030**	**120,515**	**124,517**	**129,214**	**133,769**	**138,676**
Non-industrial Peak	*103,284*	*106,277*	*109,078*	*111,985*	*114,393*	*116,982*	*119,783*	*122,870*	*125,268*	*127,285*
EV Peak	*818*	*1,096*	*1,468*	*1,968*	*2,637*	*3,533*	*4,734*	*6,344*	*8,501*	*11,391*
Existing Resource Dependable Capacity	**111,500**	**111,500**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**
YEC Hydro	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*
YEC Thermal	*35,450*	*35,450*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*
AEY Thermal	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*
N-1 Event [Loss of AH GS or L171]	**-37,195**	**-37,194**	**-37,193**	**-37,192**	**-37,191**	**-37,190**	**-37,189**	**-37,188**	**-37,187**	**-37,186**
Loss of AH GS	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*
Loss of AEY Haines Junction diesel	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*
Haines Junction peak	*1,305*	*1,306*	*1,307*	*1,308*	*1,309*	*1,310*	*1,311*	*1,312*	*1,313*	*1,314*
Capacity Shortfall/Surplus under N-1	**-29,797**	**-33,066**	**-40,839**	**-44,244**	**-47,321**	**-50,805**	**-54,806**	**-59,502**	**-64,056**	**-68,962**
Committed and Planned Supply Options	**2,843**	**12,247**	**26,952**	**35,018**	**35,085**	**35,152**	**35,221**	**70,289**	**70,359**	**70,429**
Diesel Replacements	*0*	*0*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*
Whitehorse #2 Uprate	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*
BESS	*0*	*7,200*	*7,200*	*7,200*	*7,200*	*7,200*	*7,200*	*7,200*	*7,200*	*7,200*
Atlin Hydro EPA	*0*	*0*	*0*	*8,000*	*8,000*	*8,000*	*8,000*	*8,000*	*8,000*	*8,000*
DSM	*2,205*	*4,409*	*6,614*	*6,680*	*6,747*	*6,814*	*6,883*	*6,951*	*7,021*	*7,091*
Moon Lake Pump Storage Phase 1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*35,000*	*35,000*	*35,000*
Capacity Shortfall/Surplus under N-1	**-26,955**	**-20,819**	**-13,887**	**-9,226**	**-12,236**	**-15,652**	**-19,585**	**10,787**	**6,303**	**1,467**
Capacity Shortfall/Surplus under N-1 w/o Atlin/ Moon Lake	**-26,955**	**-20,819**	**-13,887**	**-17,226**	**-20,236**	**-23,652**	**-27,585**	**-32,213**	**-36,697**	**-41,533**

TOPIC:

REFERENCE:

PREAMBLE: **Page 20, Table 4-1.**

QUESTION:

a) Please provide the specifics of the "Diesel Replacements" giving current dependable capacity of each engine being retired, and capacity of each corresponding replacement.

ANSWER:

(a)

YEC's 10-Year Renewable Electricity Plan includes the development of 12.5 MW of replacement diesel capacity at three different existing plant sites. This was based on considering the results of the technical, environmental and socio-economic research, as well as public feedback where YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired.

The Plan includes consideration of the following near-term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Generation Station - three existing Mirrlees units were retired in the past, with three LNG units replacing the two units that were initially retired; the third 4.5 MW unit that will now be replaced was retired more recently.

- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit.

- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

TOPIC:

REFERENCE: **Given the many conditions of this agreement that have not yet been met, including funding, environmental and government approvals, TRTFN approval, etc., and that the EPA has no legal force until all conditions are met, there appear to be many ways that the Project could fail.**

PREAMBLE:

QUESTION:

a) What costs have been incurred so far, and how much of this total will be passed on to ratepayers if the Project does not go forward?

b) Please provide a breakdown of all costs incurred by the Project to date, and forecast to be spent on the Project previous to meeting of conditions of the EPA and (assumed) approval of the EPA.

ANSWER:

(a) and (b)

Please see YUB-YEC-1-43(b).

UTILITIES CONSUMERS' GROUP
(UCG)

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 7**

THELP has hired SNC Lavalin to provide Owner's Engineering services for THELP's Plant, and is undertaking contractor selection as required for Project equipment procurement, installation and construction.

THELP is responsible for all AEY and YEC system upgrade costs needed to connect the Project to the YIS.

Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer- AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY.

QUESTION:

a) How much will the Buyer-AEY System Interconnection Study and Report cost ratepayers?

b) How much will the Interconnection Agreement between THELP, YEC and AEY cost ratepayers?

ANSWER:

(a)

There are not separate Buyer-AEY System Interconnection Study and Report costs. As noted in the above referenced quote from page 7 of the submission, there is a single Interconnection Study Report attachment to the Interconnection Agreement. Please see the response to YUB-YEC-1-43(b) for details on costs. All Buyer-AEY Interconnection Study Report costs will be paid by THELP, not YEC or AEY. There will be no cost to ratepayers for this work.

(b)

Please see the response to YUB-YEC-1-43(b) for details on costs. Each party will pay their own negotiation costs; YEC will apply to be compensated for its share of these costs at a future GRA. There are no other costs to ratepayers related to the Interconnection Agreement.

REFERENCE: **Proposed Atlin Hydro Expansion Project <u>Page 6 and 7</u>**

The Yukon Environmental and Socio-economic Assessment Board (YESAB) for construction and operation of a 42 km, 3-strand, 69 kV transmission line from Jakes Corner to the British Columbia border. The YESAB Teslin Designated Office issued its Evaluation Report on September 10, 2021, recommending that this project proceed subject to four recommended terms and conditions. A Decision Document has not yet been issued by the Yukon Government.

QUESTION:

a) How much will the YESAB Assessment cost ratepayers?

ANSWER:

(a)

THELP is responsible for the cost of the YESAB Assessment. Yukon Energy is not responsible for, nor will it incur, any costs related to the YESAB Assessment. As such, there are no specific costs to ratepayers for this activity.

REFERENCE: **Section 2.1 Proposed Atlin Hydro Expansion Project Page 8**

The EPA was negotiated over a period of approximately 18 months. The Parties used as a starting template for the negotiation an amalgam of the YEC Standing Offer Program (SOP) EPA and the BC Hydro Independent Power Producer (IPP) Large Project EPA, and certain other commercial principles entered into between THELP and Yukon Energy effective January 14, 2022.

QUESTION:

a) How much will the 18-month negotiation and EPA cost ratepayers? Explain.

ANSWER:

(a)

Please see response to YUB-YEC-1-43(b).

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 8**

The Project will also include upgrades as required to connect the THELP's Plant to the YIS (defined in the EPA as "Buyer-AEY System" and "Buyer-AEY System Upgrades"). Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY.

QUESTION:

a) How do you expect the YUB to make a rational informed decision on this submission before all information about the EPA is fully represented?

b) Will there not be AEY scoping costs for study, negotiations and report? How will this be handled in determining added ratepayer costs?

c) Can YEC assure stakeholders that no hidden costs will be added to ratepayers on top of the energy purchase costs and the capacity costs?

ANSWER:

(a)

The Submission sets out the information needed by the YUB to provide its report to the Minister (see response to YUB-YEC-1-1 for summary review). The YUB report is to be focused on the EPA - a document that has been completed and available for full review.

In addressing the Minister's Terms of Reference, the Submission confirms the need for the EPA Atlin Project and the basis for this Project being selected over alternative options, the high level of certainty as to the limits on costs for the utilities and ratepayer impacts due to the EPA terms, and the resulting limits on risks to the utilities and ratepayers. By way of example, the above referenced quote on completing the Buyer-AEY System Interconnection Study Report and the Interconnection Agreement addresses one of the outstanding matters to be resolved (i.e., one of the conditions precedent) before the EPA comes into full effect and the Project proceeds – however, the EPA specifically provides

that System Upgrade costs and related details are to be fully funded by THELP and will have no impact on ratepayer costs.

The major uncertainties today regarding this Project and the EPA are identified in the EPA section 2.1(d) list of conditions precedent. As reviewed in Section 4.3 of the Submission, the EPA conditions precedent identify initial risks associated with bringing the EPA into legal force. These risks have minimal if any impact on YEC, on the rates for customers, or on the prudence of proceeding with the EPA at this time. If the EPA is unable to proceed due to failure to complete its Conditions Precedent YEC will know this outcome well before the end of 2022, with ample time to proceed with rented diesel options as required for 2024/25 and subsequent years to ensure reliability of service to customers while other permanent renewable options are reviewed and developed.

(b)

As noted at page 27 of the Submission, the EPA also provides for costs for studies and other works to be fully funded by the Project (i.e., by THELP and not by the utilities) with advance payments as required. AEY will pay for its own costs to negotiate the Interconnection Agreement. Prior to such costs being included in rates they would need to be brought by AEY to the YUB for review.

(c)

As noted at page 27 of the Submission, the EPA also provides for any YEC costs for studies and other works to be fully funded by the Project (i.e., by THELP and not by the utilities) with advance payments as required. The only costs not funded by THELP relate to YEC's EPA negotiation costs and costs related to this Submission to the YUB. These costs will be brought before the YUB for review prior to being included in rates.

TOPIC:

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 9**

YEC's Target COD – target of June 1, 2024 for YEC to complete all Buyer-AEY System Upgrades (expect AEY Upgrades to be completed in Q1 2024). YEC is responsible under the EPA for Buyer- AEY System Upgrades,13 and will exercise commercially reasonable efforts to achieve YEC's COD prior to YEC's Target COD. YEC will have no liability for delays in completion of Buyer-AEY System Upgrades.

PREAMBLE:

QUESTION:

a) Which contractor has been hired to do the system upgrade for the YEC?

b) Will the YEC manage this upgrade in-house? Will there be costs associated with this to be passed on to ratepayers?

c) How does YEC ensure there will be no charges back to ratepayers for this portion of the project, i.e. Buyer-AEY System Upgrades?

ANSWER:

(a), (b) and (c)

Hatch has provided YEC with the assessment of the scope and planning level costs for YEC system upgrades. AEY has developed the scope and planning level costs for AEY system upgrades. No contractors have yet been retained to carry out the system upgrades. YEC will manage its own system upgrade work.

The EPA specifically provides that THELP is responsible for all costs related to system upgrades required for the Project to proceed. YEC will ensure that there will be no charges back to ratepayers for Buyer-AEY System Upgrades by following the terms and conditions of the EPA – including securing advance payments from THELP for this work.

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 14 <u>Table 3-1: Summary EPA Energy and Capacity Pricing</u>**

[16] The price is within the range for estimates of YEC levelized cost of capacity (i.e., fixed capital and O&M costs, excluding fuel costs) for a 12.5 MW new diesel generation facility. Foot note p. 13

QUESTION:

a) From this table, it is difficult to tell how pricing for energy delivered will be evaluated, will it be the blended rate or the firm and non-firm rates? Please explain.

b) From this table, there is a summer energy price. Would the current secondary energy price pay for this amount plus YEC management fees? Please explain.

c) From table 3-1, a Dependable Plant Capacity Commitment and then taking into account the above footnote, of how this capacity cost to be paid to THELP is determined, does this cover all the fixed capital costs of an alternative 12. 5MW diesel plant alternative minus the Federal and YG grant amounts to be contributed to the project? Explain.

d) Is it proposed that the Yukon portion of the grant be directly from YG or through YDC? If it goes through YDC is there a plan to place this amount on our rate base? Explain.

ANSWER:

(a)

Winter energy delivered will be paid the Firm Winter Energy Price for the first 25.2 GWh delivered in a calendar year, and the Non-Firm Winter Energy Price for all additional energy delivered in a calendar year. Please see YUB-YEC-1-11 for review of the determination of these energy prices.

(b)

The EPA summer energy price is not designed to support secondary (interruptible) sales.

The EPA provides that YEC will only receive summer delivered energy when YEC specifically requests such energy and YEC would not make this request unless it was required to displace thermal generation during this period. In this specific situation where thermal generation is required on the system, YEC would not offer secondary sales as prescribed by the secondary sales rate schedule rules.

(c)

The $200/kW-yr (2024$) dependable capacity price covers the per kW capital and non-fuel O&M levelized costs for a new diesel plant (see response to YUB-YEC-1-13(a) for more detailed review). There are no deductions for any grant funds provided to THELP, as YEC would not expect that grant funding would be available for YEC to develop a new greenfield diesel plant.

(d)

The exact routing of funding has not been agreed; it is possible that YDC could be involved in the transfer of funds from YG to THELP. YEC will not be contributing funding directly for the Atlin project.

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 20**

Table 4-1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (kW) **2021/22 2022/23 2023/24 2024/25 2025/26 2026/27 2027/28 2028/29 2029/30 2030/31**
Committed and Planned Supply Options 2,843 12,247 26,952 35,018 35,085 35,152 35,221 70,289 70,359 70,429

Diesel Replacements 0 0 12,500 12,500 12,500 12,500 12,500 12,500 12,500 12,500 Whitehorse #2 Uprate 638 638 638 638 638 638 638 638 638 638 BESS 0 7,200 7,200 7,200 7,200 7,200 7,200 7,200 7,200 7,200 Atlin Hydro EPA 0 0 0 8,000 8,000 8,000 8,000 8,000 8,000 8,000 DSM 2,205 4,409 6,614 6,680 6,747 6,814 6,883 6,951 7,021 7,091 Moon Lake Pump Storage Phase 1 0 0 0 0 0 0 0 35,000 35,000 35,000

QUESTION:

a) Please explain Diesel Replacement program scheduled for 2023/2024 to achieve this goal.

b) Please explain all DSM programs for each year starting 2021/2022 yr. to 2030/2031 yr. inclusive to achieve these goals.

ANSWER:

(a)

YEC's 10-Year Renewable Electricity Plan includes the development of 12.5 MW of replacement diesel capacity at three different existing plant sites. This was based on considering the results of the technical, environmental and socio-economic research, as well as public feedback where YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired.

The Plan includes consideration of the following near-term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Generation Station - three existing Mirrlees units were retired in the past, with three LNG units replacing the two units that were initially retired; the third 4.5 MW unit that will now be replaced was retired more recently;

- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit; and

- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

(b)

The DSM savings goals were based on a high-level conservation potential review for Yukon, and do not reflect detailed measure information. These estimates will be used to set targets for DSM programs and inform the scope and scale of the designs. It is expected that the DSM program design will include capacity-focused DSM programming, with a particular focus on limiting the peak demand impact of electrification policy initiatives. Examples of the potential programs being considered to achieve these goals include electric heat thermostat and hot water tank remote control (e.g., demand response), and electric vehicle charger timers or controllers.

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 26**

The least costly new source would likely be new thermal generation with an LCOC (2024$) of at least $200/kW-year or $1.6 million/year for 8.0 MW.

QUESTION:

a) Why did the YEC not more proactively pursue a new thermal generation project for years now?

ANSWER:

(a)

The referenced quote is addressing securing equivalent (i.e., permanent) new dependable capacity from another source than the Atlin project. In this context, rented diesel was not relevant. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[1] Rented diesels, however, have proved to be a cost-effective short-term option to address the current dependable capacity shortage.

Contrary to what is suggested in the question, YEC did actively pursue new permanent thermal generation project options following the 2016 Resource Plan.

- Following the 2016 Resource Plan, YEC diligently pursued permanent solution options, including the 20 MW new diesel plant, the third LNG unit, the BESS project, dependable capacity DSM, and potential new dependable hydro capacity options. Given these actions there is no basis for suggesting that YEC was imprudent or irresponsible in its planning to address the dependable capacity gap.

[1] YUB Report to Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

- As a result of detailed planning assessments (including consultation and engagement on the 20 MW new diesel plant site options that identified stakeholder concerns with this option), YEC's Board in 2019 rejected that alternative for further consideration and directed that new permanent thermal options focus on diesel replacement at existing plants.

- Yukon Energy is currently diligently acting to implement the 10 Year Renewable Electricity Plan that includes diesel replacement options at existing diesel plants, renewable capacity alternatives including BESS, dependable capacity DSM, and dependable hydro capacity provided by the Atlin Hydro Expansion project and the Tutshi-Moon Lake Pumped Storage project.[2]

- Yukon Energy has confirmed that as at 2019, when the decision was made to not pursue the 20 MW new diesel plant option after completion of detailed planning work, it would have taken at least four years to plan, permit and construct a new 20 MW or 12.5 MW diesel plant, i.e., such a new diesel plant could only have been available in 2023 at the earliest.[3] In other words that option -- even if it was pursued -- could not have been in service to date.

[2] 2021 GRA CW-YEC-2-6(a) and (b). These investigations were detailed in the response, with reference to 2021 GRA CW-YEC-1-36(a) Attachment 1 copy of the YEC 10-Year Renewable Electricity Plan completed during 2020. Ms. Milojevic also reviewed the extensive work done by YEC to identify and cost options for the 2016 Resource Plan and the current 10-Year Renewable Electricity Plan, 2021 GRA Transcript pages 458-460.

[3] Mr. Hall, Ms. Milojevic, 2021 GRA Transcript pages 454-456.

REFERENCE: **Proposed Atlin Hydro Expansion Project <u>Page 26</u>**

There is some uncertainty with respect to what, if any impact the EPA may have on YECs balance sheet (i.e., rate base). Based on preliminary assessments of the Agreement, YEC has concluded that this transaction does not contain a capital lease and therefore there is no balance sheet or rate base impact. This conclusion, however, is not final. The ultimate impact can only be known when the Project is complete and YECs auditors (the Auditor General of

QUESTION:

a) How much would a possible impact cost to the ratepayers if a balance sheet or rate base is required? Please explain and discuss.

b) How would this affect the bottom line on consumer rates?

ANSWER:

(a) and (b)

Please see response to YUB-YEC-1-42.

TOPIC:

REFERENCE: **Proposed Atlin Hydro Expansion Project Page 26 Footnote 41**

[41] The $5.3 million/year (2024$) until the end of 2034 assumes 8.0 MW dependable capacity ($1.6 million/year) plus 30.8 GWh/year winter delivered energy ($3.7 million/year per Appendix A, Table A3-2). The Project is capable of providing 5.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 5.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.5 million/year (price at 50% of the approved blended fuel cost).

PREAMBLE:

QUESTION:

a) Is this $5.3 million per year total cost ($1.6 million dependable capacity plus $3.7 million delivered energy), all the proposed costs that will be passed on to ratepayers? If not, explain.

b) Please discuss the pros an [sic] cons of summer deliverable energy for secondary usage.

c) Would the current approved secondary charge be sufficient to cover the proposed summer rate of 50% of the approved fuel cost plus YEC management costs? Please elaborate.

ANSWER:

(a)

The referenced costs are the total costs for energy delivered during the winter period when there is no carbon charge applicable to ratepayers, no Monthly Constraint Energy, and (after 2034) no Added Load. This cost is stated in 2024$ and is subject CPI increases as

noted in the EPA and Table 3-1 of the Submission. Negotiation and YUB proceeding costs for the EPA to be recovered from ratepayers are not included in the referenced costs.

(b) and (c)

Please see response to UCG-YEC-1-6(b).

REFERENCE: **Proposed Atlin Hydro Expansion Project Construction and Commissioning Page 27**

Once the EPA Conditions Precedent are completed, YEC costs and customer rates are not affected by THELP's cost and funding risks related to construction and commissioning of the Project. YEC and AEY system upgrades required by the EPA are also to be fully funded by the Project at no cost to the utilities or customer rates.

QUESTION:

a) What about YEC costs prior to EPA conditions being met? Who pays for these costs? Explain.

b) What about AEY costs prior to EPA conditions being met? Who pays for these costs? Explain.

ANSWER:

(a) and (b)

As noted on page 27 of the Submission, YEC and AEY costs for all studies and other works (including those done before EPA conditions are met) are to be fully funded by the Project (i.e., by THELP and not by the utilities) with advance payments as required. The only costs not funded by THELP relate to EPA agreement negotiation costs of each party. These specific YEC and AEY costs will be incurred regardless of whether the EPA conditions are met. YEC would seek future recovery of such costs in its next GRA.

REFERENCE: **Proposed Atlin Hydro Expansion Project Construction and Commissioning P. 29**

Although YEC will bear the cost for Monthly Constraint Energy (i.e., Delivered Energy that THELP could not deliver due to a Non-Permitted System Constraint caused by YEC or AEY) this risk is controlled by YEC and AEY and is considered to be minimal in terms of impacts on YEC costs or customer rates. YEC will seek to recover from AEY, through the Implementation Agreement, any such costs due to a Non-Permitted System Constraint on the AEY System.

QUESTION:

a) Please explain what non-permitted system constraint energy is? Give examples.

b) Why is this not defined in the EPA?

ANSWER:

(a) and (b)

A Non-Permitted System Constraint is defined in the EPA at Section 6.5 and in Appendix A, section 1.101.

Section 6.5 specifies that a Non-Permitted System Constraint occurs if, in any month after the Buyer's COD, the Seller is unable to deliver Delivered Energy that Seller is permitted to deliver under the EPA solely as a result of a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and which is not caused by:

(a) Buyer-AEY Planned Outage; or
(b) Seller, Seller's Plant or anything on Seller's side of the Point of Interconnection.

As defined in the EPA, a Buyer-AEY System Constraint "means any disconnection of Seller's Plant from Buyer-AEY System, or any outage, suspension, constraint, or curtailment in the operation of Buyer-AEY System preventing or limiting deliveries of Delivered Energy at the POI or within the Buyer-AEY System or any direction from Buyer

to Seller to reduce generation of Seller's Plant as a result of any outage, suspension, constraint, or curtailment in the operation of the Buyer-AEY System."

Section 6.5 provides that Buyer will have no liability for a Buyer-AEY System Constraint (or be in breach of Sections 6.3 or 8.2) unless it is a Non-Permitted System Constraint as defined in Section 6.5. To be a Non-Permitted System Constraint for which YEC will pay the Monthly Constraint Energy calculated for the relevant month under Schedule F, the Buyer-AEY System Constraint must:

- Prevent Seller to deliver Delivered Energy that Seller is permitted to deliver under this EPA;
- Be solely the result of a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and is not caused by (a) Buyer-AEY Planned Outage, or (b) Seller, Seller's Plant, or anything on Seller's side of the POI; and
- Not be subject to exemptions set out in Section 6.5 when Buyer will not be required to pay for any Monthly Constraint Energy.[1]

Please see response toYUB-YEC-1-25(a) for an example of Monthly Constraint Energy determinations pursuant to Schedule F of the EPA.

Seller will maintain and complete Records of all Constraint Shortfall Energy avoided or, acting reasonably, could have been avoided during a Non-Permitted System Constraint by reducing or shutting down water deliveries to the Upper Powerhouse and will report such amounts to Buyer in writing and provide Buyer with all information required to calculate such amounts.

Buyer will give Seller Notice of all Buyer-AEY System Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly invoices under Section 8.8. If there is a Dispute between the Parties for the amount of any Monthly Constraints Energy Amount, the Dispute will be resolved under Article 18.

[1] Section 6.5 lists four subsection exemptions as subsections "c" through "f", including Force Majeure, any period when Seller's Plant would otherwise not have been operating, any period specified as a Seller's Outage in any Outage Notice or a revised Outage Notice, or when the Non-Permitted System Constraint is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2 of the EPA.

YUKON UTILITIES BOARD
(YUB)

ISSUE: **Need, timing and proposed terms and conditions**

REFERENCE: **May 18, 2021 Minister McPhee's letter - Referral of the Electricity Purchase Agreement with Tlingit Homeland Energy LP**

QUOTE: "3. The YUB shall report on, and make recommendations about, the necessity for the Agreement, its timing, and proposed terms and conditions, with particular regard to:

a. The public need for the Agreement under various reasonable electric load forecasts.

b. The effect of the proposed commitments on the rates of customers and the reliability of electricity service provided to customers.

c. The capability of existing and currently committed and expected generation and transmission facilities including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements in (a) and the effect of the Agreement on this capability.

d. The risks associated with the Agreement, including its potential impacts on YEC and rates for customers and on the reliability of electricity service provided to customers.

e. Evidence that all reasonable alternative options have been considered, and that proposed spending commitments have been selected on reasonable grounds.

f. Whether it is prudent to enter into the Agreement as proposed at this time."

QUESTION:

a) Please provide a summary of how YEC's application meets each item in the enumerated list from the Minister (and in terms of need, timing and with reference to the terms and conditions in the agreement).

b) How do the terms of the agreement, and specifically the conditions precedent in the agreement, affect the Board's review of factors (a) to (f) above?

ANSWER:

(a) and (b)

Part 4 of Yukon Energy's Submission addresses each of the items in the enumerated list from the Minister:

1. Item 3(a) of the Minister's list is addressed in section 4.1 of the Submission, which also includes:
    a. Section 4.1.1 which addresses item 3(c) of the Minister's list: and
    b. Section 4.1.2 which addresses item 3 (e) of the Minister's list.
2. Item 3(b) of the Minister's list is addressed in Section 4.2 of the Submission.
3. Item 3(d) of the Minister's list is addressed in Section 4.3 of the Submission.
4. Item 3(f) of the Minister's list is addressed in Section 4.4 of the Submission.[1]

In summary, Section 4 of the Submission documents the need for the EPA and its prudence under reasonable electric load forecasts.

- The EPA provides 8.0 MW of renewable dependable capacity during the Peak Winter Period (displacing the equivalent of four rented diesels) as well as LTA annual Winter Period renewable energy of 30.8 GWh that is expected to displace between 15.0 and 19.6 GWh/year of LTA thermal generation over the 40 year EPA term.

- The EPA enables the only near-term resource option other than the BESS to provide material added renewable dependable capacity benefits.

- The EPA provides for all required YEC/AEY study and asset development costs (e.g., for required System Upgrades) to be fully funded in advance by THELP at no cost risk to the utilities or Yukon ratepayers.

[1] Section 3 of the Submission also reviews the key terms and conditions for each part of the EPA. These terms and conditions establish the energy and dependable capacity to be supplied to YEC over the 40-year term, and the costs, prices, payment terms and risks for YEC to purchase the energy and dependable capacity provided under the EPA.

- The EPA impacts on ongoing YEC costs and customer rates are tied to actual THELP deliveries of energy and dependable capacity, and mirror or improve on what would be expected to occur with the least cost permanent thermal resource option. The EPA effect on customer rates is materially lower than the option of equivalent renewable SOP IPP renewable supplies.

- The EPA is expected to maintain, and likely to enhance, current service reliability.

- The EPA places on THELP all risks related to development of the Project, including permitting, securing necessary grant funding, capital costs to complete, and schedule (including completing all condition precedents needed for the EPA to come fully into force for development of the Project).

- In the event that the EPA does not proceed, or it proceeds but the Project in-service is delayed, the EPA retains YEC ability to sustain reliable service using existing YIS resources plus rented diesel units as required for dependable capacity requirements.

- The EPA specifies the timelines required for the Project to proceed in order to secure access to these new renewable energy and dependable capacity resources on a timely and cost effective basis.

As reviewed in Section 4.3 of the Submission, the EPA conditions precedent identify initial risks associated with bringing the EPA into legal force. These risks have minimal if any impact on YEC, on the rates for customers, or on the prudence of proceeding with the EPA at this time. If the EPA is unable to proceed due to failure to complete its Conditions Precedent YEC will know this outcome well before the end of 2022, with ample time to proceed with rented diesel options as required for 2024/25 and subsequent years to ensure reliability of service to customers while other permanent renewable options are reviewed and developed. The fact that the Conditions Precedent remain unresolved at this time does not preclude the Board from assessing the EPA as directed by the Minister based on available information as provided by YEC in its Submission.

ISSUE: **Hydro energy from the Atlin hydro expansion project with THELP**

REFERENCE: **Application, page 1, PDF page 4**

QUOTE: "It can provide the Yukon Integrated System ("YIS") at Jakes Corner with 8 MW of winter dependable capacity and 36 GWh/year of long-term average renewable hydro energy if operated throughout the year."

QUESTION:

a) How accurate is the assumption that the renewable hydro energy will be operated throughout the year?

b) If the Atlin hydro expansion project is operated throughout the year, how likely is it that YEC facilities will spill water due to water license restrictions, which would mean that YEC would not generate electricity from that spilled water?

ANSWER:

(a)

The quote indicates that the project can provide LTA energy capability if operated throughout the year and dependable capacity capability during winter. The EPA, however, specifies a commitment for YEC to purchase energy only during the defined Winter Period (January-May, and September-December, inclusive), i.e., the Project will not operate during the Summer unless YEC specifically requests an energy delivery (which is not expected to occur under normal conditions).

(b)

YEC has substantial surplus renewable generation forecast in the summer period such that Atlin energy provided during this period would be expected only to add to YEC facility spill of water without any material added LTA thermal generation displacement during a year. Under the EPA there will be summer energy deliveries only when requested by YEC as justified in the circumstances, with a separate price for any such deliveries equal to 50% of the last YUB approved blend fuel thermal price. YEC would only exercise this

option when thermal generation was otherwise required on the YIS in summer. Buying summer energy from Atlin in this case would be cheaper than running YEC thermal assets.

The YEC Submission estimates that LTA winter EPA deliveries will also have some YEC facility spill of water – however, material added LTA thermal generation displacement is also expected to result from these EPA deliveries throughout the 40 year term of the EPA. Please see response to YUB-YEC-1-11 and YUB-YEC-1-12 for additional analysis.

ISSUE: **Project funding**

REFERENCE: **Application, page 1, PDF page 4**

QUOTE: "THELP is proceeding to secure approvals and permits for the Project, and YEC and THELP are collaborating on securing the necessary government funding."

QUESTION:

a) Has YEC or its parent YDC directly or indirectly contributed any funds to the project – e.g., the work to secure funding? Please explain.

b) Will YEC or YDC be providing any funding for the project? Please explain.

c) Please explain how each of the funding sources and amounts (expected to be secured or already secured) will impact both YEC and ratepayers.

ANSWER:

(a)

No. Neither YEC nor YDC have contributed funds directly to the Atlin project. YEC has incurred and will incur costs related to supporting THELP as necessary to secure funding from governments. The amount is expected to be less than $0.050 million.

(b)

Not directly. The exact routing of funding has not been agreed; it is possible that YDC could be involved in the transfer of funds from YG to THELP. YEC will not be contributing funding directly for the Atlin project.

(c)

The total funding for this project is used to effectively provide an acceptable return to the project proponent while ensuring the buyer pays pricing that is at or lower than the cost of thermal alternatives.

ISSUE: **Project description**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: "The Project is an 8.7 MW hydroelectric facility that expands, but is separate from, the Existing Plant, although it uses the same Surprise Lake storage (expanded with the new THELP Plant) and Pine Creek water flows."

QUESTION:

a) Can both the Atlin hydro expansion project and the Existing Plan (sic) simultaneously operate at full capacity and for extended periods? Please explain with supporting details.

ANSWER:

(a)

It is assumed that the question is referencing the Existing Plant and the Atlin hydro expansion project (the Project) as identified in the EPA.

The Project and the Existing Plant can simultaneously operate at full capacity for extended periods during the Peak Winter Period (PWP) as defined in the EPA (December 16 to end of February); however, water availability and winter storage requirements can limit this capability during other parts of the year.

The Project capability to provide full capacity during the PWP is reviewed in detail in Section 1.1 of Appendix B of the Submission – including reference to estimated water availability to Seller's Plant over 35 water years (Appendix A, Table A2) assuming forecast Atlin BC Hydro load for 2032 at 6.93 GWh (see Table A1). The following is noted in Section 1.1:

- Based on the assumptions adopted for the LTA delivered energy estimates, expected LTA energy deliveries from the Project to YEC during each PWP over the 35 water years would equal at least 14 GWh and be sufficient to enable a full 8.0 MW of capacity to be delivered to YEC at Jakes Corner for 94% of the PWP

days, i.e., for 70.5 of the 75 or 76 days in the PWP, which is more than enough days to cover all of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse during the PWP period.

- Table A2 of the Submission confirms that the above outcome is expected even when the Surprise Lake reservoir is not full in the prior October (based on the one relevant historic water year), so long as the Existing Plant load requirement is at 6.93 GWh/year or less (load forecast for 2032).[1]

- To assess sensitivity of dependable capacity to possible higher Existing Plant loads, the following have been confirmed:[2]
    - If Surprise Lake is full in the prior October, the ability to provide 14 GWh of delivered energy to YEC at Jakes Corner (and the dependable capacity at 8.0 MW provided for 94% of the PWP days) is retained regardless of possible Existing Plant load level increases examined (up to 9 GWh per year total load).
    - If Surprise Lake is not full in the prior October, it has been confirmed that so long as the Existing Plant load does not exceed 9 GWh/year, water availability is adequate for LTA delivered energy to YEC during the PWP to be at least 12 GWh, which is sufficient to enable a full 8.0 MW of capacity to be delivered at POI for at least 37 full days (with balance of PWP days at 65% of 8.0 MW), i.e., confirmed ability to accommodate at full capacity at least one two-week cold temperature period plus at least 23 additional days if needed.

[1] The forecast LTA deliveries from the Project assume that the load for the Existing Plant to supply the BC Hydro Atlin community load is 6.93 GW.h/yr. based on load forecast for 2032.
[2] Section 7.2(a) of the EPA restricts modifications to the Existing Plant which would have a material adverse effect on Seller's ability to meet these energy deliveries during each PWP.

ISSUE: **Project description**

REFERENCE: **Application, pages 2-3, PDF pages 5-6**

QUOTE: "A 92 km 69 kV new transmission line from a new substation at the new hydro facilities to a new interconnection substation at Jakes Corner, YK with interconnection to the YIS at the existing 34.5 kV ATCO Electric Yukon ["AEY'] facilities ["AEY System"] for transmission to YEC's S-150 substation in Whitehorse."

QUESTION:

a) Please describe whether each of the facilities listed in the quote are regulated or unregulated, and if regulated, whether YUB or BCUC is the regulator.

ANSWER:

(a)

Under the EPA THELP is responsible for the regulatory requirements for all of the Seller's Plant facilities including the 92 km 69 kV new transmission line and substations identified in the quote. It is YEC's understanding that none of these facilities are regulated by either the YUB or BCUC.

The AEY and YEC facilities referenced in the quote are regulated by YUB.

ISSUE: **Project description**

REFERENCE: **Application, page 3, PDF page 6**

QUOTE: "The Project will also include upgrades to the YIS to accommodate the Project's capacity and energy deliveries (primarily involving AEY System transmission upgrades)."

QUESTION:

a) Please describe these upgrades and who will be responsible for the upgrades (YEC or AEY).

b) Where does YEC expect the upgrades to regulated facilities to be included in rates (YEC and/or AEY's rates)?

ANSWER:

(a)

Please see response to YUB-YEC-1-9(a) for current description of upgrades to be done to the YIS. Under the EPA, YEC has overall responsibility for all upgrades done to the YIS; the Interconnection Agreement and Implementation Agreement address YEC arrangements for AEY responsibilities for the upgrades to its part of the YIS that requires upgrades. Overall, YEC is directly responsible for upgrades located at Whitehorse substation S150, at Jakes Corner Interconnection Substation being developed by THELP, and SCADA related upgrades at Atlin hydro expansion facilities to be developed by THELP. AEY will be responsible for upgrades located on the AEY system between Jakes Corner and S150 at Whitehorse.

(b)

The upgrades to regulated facilities of YEC and AEY will be fully funded by THELP and therefore have no impacts on YEC or AEY rates.

ISSUE: **Project options**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: "Its significantly shorter project development timeline when compared to other greenfield hydro options (reflecting its expansion of TRTFN's existing Atlin hydro project and the feasibility work already completed for the expansion project)."

QUESTION:

a) Please describe and explain the other options referred to in the above quote. In your response, please identify what non-renewable options were explored.

b) Why was the Altin hydro expansion project the preferred option in terms of both the reasons for the project and project cost?

ANSWER:

(a)

Section 4.1.2 of the Submission describes and explains that the other renewable greenfield hydro options referred to in the above quote are the other small hydroelectric project options in Yukon and northern British Columbia examined in the Knight Piesold Ltd. review reported on in (and attached to) YEC's 10-Year Renewable Electricity Plan (see YUB-YEC-1-32, Attachment 1).

The 10-Year Renewable Electricity Plan also reviewed non-renewable options, including replacement of retired diesel units (see Table 4-1 in Submission). The Submission also considered LCOC costs for greenfield new diesel generation (see footnote 16 in the YEC Submission).

(b)

Please see Section 4.1.2 of the Submission which reviews alternative options to the project other than the BESS that is now being developed. The focus was on renewable hydro generation with storage (that could provide dependable capacity) - the Atlin option

has a significantly shorter project development timeline compared to other greenfield hydro options, reflecting the factors noted in the above quote.

The following was also noted in Section 4.1.1 of the YEC Submission:

> "The only other alternative identified to date for meeting the capacity shortfall without rented diesels would be to develop additional permanent thermal (diesel) capability beyond the planned replacements of retired units. As reviewed in the BESS proceeding, the development of new permanent diesel plants is not supported by stakeholders and is also not in line with goals outlined in Yukon government's draft "Our Clean Future: A Yukon strategy for climate change, energy and a green economy." As reviewed in Section 4.2 below, EPA impacts on customer rates are designed to mirror or improve upon the impacts to be expected with a permanent thermal generation option."

Dependable capacity for thermal generation was benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[1]

[1] YUB Report to Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

ISSUE: **BC Hydro Supply Agreement**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: **"In 2009 the TRTFN, through an affiliate of THELP, developed a 2.1 MW hydroelectric power station at Atlin, BC, on Pine Creek with hydro storage at Surprise Lake (the "Existing Plant"). The Existing Plant has an existing electricity purchase agreement with BC Hydro to supply BC Hydro load at Atlin until 2033. THELP expects that a further EPA will be negotiated with BC Hydro for supply after 2033."**

QUESTION:

a) Please provide a copy of the agreement referenced above.

ANSWER:

(a)

Please see Attachment 1 to this response. The agreement referenced above is also available from the BCUC at the link provided below:

https://www.ordersdecisions.bcuc.com/bcuc/orders/en/116883/1/document.do

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-91-08

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

A Filing by British Columbia Hydro and Power Authority
of an Electricity Purchase Agreement and Amending Agreement
for the Pine Creek Project

BEFORE: L.F. Kelsey, Commissioner
P.E. Vivian, Commissioner
A.A. Rhodes, Commissioner

June 12, 2008

O R D E R

WHEREAS:

A. Pursuant to Section 71 of the Utilities Commission Act (the "Act") on April 2, 2008 British Columbia Hydro and Power Authority ("BC Hydro") filed with the Commission an Electricity Purchase Agreement ("EPA") dated November 21, 2006 with the Taku Land Corporation for the Pine Creek project ("Project") and an agreement (the "Amending Agreement") dated March 11, 2008 that amends the EPA; and

B. The EPA was signed on November 21, 2006 and the original Commercial Operation Date ("COD") was April 1, 2008 and amended to January 1, 2009; and

C. The Commission notes that BC Hydro did not file the EPA signed on November 21, 2006 with the Commission; and

D. On April 24, 2008, the Commission issued Information Request No. 1 to BC Hydro; and

E. On May 9, 2008 BC Hydro responded to Information Request No. 1 and confirmed that the content of the Energy Supply Contract filing for the Pine Creek Project dated April 2, 2008 is not confidential; and

.../2

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-91-08

F. The Commission has reviewed the unique characteristics and circumstances related to this EPA and its Amending Agreement and the Commission has concluded that it should be accepted for filing pursuant to Section 71 of the Act.

NOW THEREFORE the Commission orders as follows:

1. The EPA and the Amending Agreement that are attached to this Order are accepted for filing as an Energy Supply Contract and an amendment to the Energy Supply Contract, pursuant to Section 71 of the Act, subject to item 2 below.

2. BC Hydro is to notify and to submit an estimated cost to complete the Project as well as an economic analysis to the Commission for its consideration in the event BC Hydro exercises Section 16 of the EPA that specifies Step-In Rights to permit BC Hydro to construct and operate the project.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of June 2008.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner

Attachments

~~CONFIDENTIAL~~

ELECTRICITY PURCHASE AGREEMENT

PINE CREEK PROJECT

THIS ELECTRICITY PURCHASE AGREEMENT ("EPA") is made as of November 21, 2006.

BETWEEN: **TAKU LAND CORPORATION**, a British Columbia company with its office at P.O. Box 408, Atlin, British Columbia, V0W 1A0.

("Seller")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, with its Head Office at 333 Dunsmuir Street, Vancouver, B.C. V6B 5R3.

("BC HYDRO")

WHEREAS:

A. BC HYDRO wishes to purchase a reliable supply of Electricity for its customers in the community of Atlin, British Columbia.

B. BC HYDRO issued a Request for Expressions of Interest ("RFEI") dated May 28, 2005 for a long-term electricity purchase agreement to replace the existing diesel generating system in Atlin with a viable, cost-effective and reliable power generation source.

C. The Seller submitted its response to BC HYDRO's RFEI on or about July 4, 2005.

D. The Seller intends to construct, own and operate a 2 MW small hydropower generating facility on Pine Creek, approximately 4 kilometers north of Atlin for the purpose of generating electrical energy with an expected generating capability of 16 GWh per year.

E. The Seller desires to sell, and BC HYDRO desires to purchase, electrical energy generated by the Seller's Plant on the terms and conditions set forth in this EPA.

1. INTERPRETATION

1.1 **Definitions** - Appendix 1 sets out the definitions applicable to certain words and expressions used in this EPA.

1.2 **Appendices** - Attached to and forming part of this EPA are the following appendices:

Appendix 1	-	Definitions
Appendix 2	-	Tariff
Appendix 3	-	Description of Seller's Plant
Appendix 4	-	Sample Form of Mortgage
Appendix 5	-	Sample Form of General Security Agreement

1.3 **Headings** - The division of this EPA into Articles, Sections, subsections, paragraphs and Appendices and the insertion of headings are for convenience of reference only and will not affect the interpretation of this EPA.

1.4 **Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

1.5 **Governing Law** - This EPA is made under, and shall be interpreted in accordance with, the laws of the Province of British Columbia. Subject to Section 20.6, any suit, action or proceeding (a "Proceeding") arising out of this EPA may be brought in the courts of the Province of British Columbia at Vancouver, and those courts will have non-exclusive jurisdiction in respect of any Proceeding.

1.6 **Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

1.7 **Statutory References** - Reference to a statute means the statute and regulations, if any, under that statute, in force from time to time, unless otherwise stated.

1.8 **Currency** - References to dollars or $ means Canadian dollars, unless otherwise stated.

1.9 **Reference Indices** - If any index or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index or price quotation that most nearly, of those then available, approximates the intent and purpose of the index or quotation that has so ceased or changed, as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 20.6.

1.10 **Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

1.11 **Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as may from time to time be supplemented or amended and in effect, and includes the Appendices attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular Section, subsection or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto; and

(d) all rights and remedies of either party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party shall be entitled to pursue any and all of its remedies concurrently, consecutively and alternatively.

2. TERM

2.1 **Term** - The term ("Term") of this EPA commences on the date of execution and delivery of this EPA by both Parties and will continue until the 25th anniversary of COD, unless it is terminated earlier as authorized under this EPA. For purposes of this EPA, except where specific reference is made to calendar years, "Year" shall be deemed to refer to successive periods of 365 days (366 days in leap years) beginning on the day following the day on which COD occurred, and so on for the remainder of the Term.

3. CONDITIONS SUBSEQUENT

3.1 **Termination for Failure of Conditions Subsequent** - Either Party, by notice to the other Party, may terminate this EPA if the following conditions have not been satisfied or waived on or before the expiry of the Initial Period:

(a) the Seller has obtained all Material Permits;

(b) the Seller has obtained title, or another form of tenure, to the area of land and/or water on and in which the Seller's Plant will be located;

(c) the Seller and BC HYDRO have entered into an Interconnection Agreement for the interconnection of the Seller's Plant to BC HYDRO'S Plant serving the community of Atlin;

(d) the Seller has arranged financing for amounts which, together with equity investments, are sufficient to fund the design, construction and commissioning of the Seller's Plant, on terms satisfactory to the Seller;

(e) the Seller is lawfully exempt from regulation as a "public utility", as defined in the UCA with respect to the Seller's Plant, the sale of Electricity and the performance by the Seller of its obligations under this EPA; and

(f) the Seller has given notice to BC HYDRO that it has satisfied each condition in this Section 3.1, and has provided to BC HYDRO copies of the documents required to demonstrate satisfaction of the conditions in subsections 3.1(a), (b) and (c).

3.2 **Reasonable Efforts and Waivers** - The Seller shall use all commercially reasonable efforts to satisfy, as soon as practicable, the conditions in Section 3.1. A "material default" includes a failure to use all commercially reasonable efforts. The Seller is solely responsible for all costs incurred by Seller in negotiating and settling this EPA and the Interconnection Agreement, and for all costs associated with connecting the Seller's Plant to BC HYDRO'S Plant at the Point of Interconnection. The conditions set out in subsections 3.1(d) and (e) are solely for the benefit of the Seller and may be waived only by it. All other conditions are for the mutual benefit of the Parties and may only be waived jointly by the Parties. All waivers must be in writing. If a condition in Section 3.1 is satisfied or waived after the expiration of the Initial Period and prior to that time this EPA has not been terminated, then neither Party will thereafter have the right to terminate this EPA as a result of that condition not being satisfied or waived on or before the expiry of the Initial Period. If this EPA is terminated under Section 3.1, the provisions of Section 15.3 will apply.

3.3 **BCUC** –Either Party may terminate this EPA if:

(a) at any time before expiry of the Initial Period, the BCUC issues an order relating to this EPA pursuant to the UCA which has or would have a material adverse effect on the EPA and/or the economic benefits to be derived by either or both parties from the EPA, all rights of review and appeal in respect the order have been exercised or expired, and the terms of such order are not acceptable (acting reasonably) to either or both Parties; or

(b) at any time before expiry of the Initial Period, a proceeding which could result in an order as referred to in clause (a) has commenced pursuant to the UCA relating to this EPA and is pending on the expiry of the Initial Period.

A Party entitled to terminate this EPA under this Section 3.3 may do so by giving notice to terminate to the other Party within 30 days after the right to terminate arises under subsection 3.3(a) or 3.3(b) as the case may be. If a Party does not exercise its right to terminate within that 30 day period, it is deemed to have waived that right to terminate. Notwithstanding the foregoing, if a proceeding as referred to in clause 3.3(b) is pending on the expiry of the Initial Period and it reasonably appears that a decision or order in the proceeding will be made within 60 days after the Initial Period expiry date, no notice of termination shall be given until after the expiry of the said 60 day period; or, if the decision or order is earlier issued, then until after the decision or order has been issued, but in that case only if the decision or order is to the effect referred to in clause 3.3(a). If this EPA is terminated under this Section 3.3, the provisions of Section 15.3 will apply.

4. DOCUMENTS TO BE PROVIDED BY SELLER

4.1 **Quarterly Status Reports** - On each of January 1, April 1, July 1 and October 1, commencing with the earliest of those dates after the date on which this EPA is made as specified on page one of this EPA, and continuing until COD, the Seller shall deliver to BC HYDRO a report on the status of the financing for the Seller's Plant, all Permit applications for the Seller's Plant, the tenure for the Seller's Plant, the design, engineering, equipment procurement, construction and commissioning of the Seller's Plant, the expected COD, the progress of work and installation of facilities under the Interconnection Agreement, the status of the Seller's efforts to obtain the exemption referred to in subsection 3.1(e) and the status of the Seller's efforts to secure the Energy Source for the Seller's Plant. If the Seller expects that COD will be achieved at a date other than Target COD, the Seller shall advise BC HYDRO as soon as reasonably practicable and, in any event, not later than in the next report required under this Section 4.1 and the Seller will state the reasons for the change in the expected COD.

4.2 **Interconnection Agreement Defaults** – The Seller shall give promptly to BC HYDRO's representative for notices under this EPA as shown in subsection 20.3(c) a copy of any notice of a breach of, or default under, the Interconnection Agreement, whether given or received by the Seller.

5. COD

5.1 **Construction of Plant and Target COD** - The Seller shall proceed diligently to complete the design, construction, interconnection and commissioning of the Seller's Plant. Thereafter, the Seller shall use all commercially reasonable efforts to achieve COD by the Target COD. If, despite such efforts, the Seller is not able to achieve COD by the Target COD, the Seller shall continue to use all commercially reasonable efforts to achieve COD at the earliest date practicable thereafter.

5.2 **Requirements for COD** - Subject to subsection 5.5(a), COD will be the date on which all of the following have occurred:

(a) the Seller has received all Permits required to operate the Seller's Plant;

(b) BC HYDRO has issued a completed and executed Declaration of Compatibility-Generator (Operating), or such other document of similar effect as may be substituted therefor, to the Seller under the Interconnection Agreement;

(c) the Seller's Plant has generated Electricity as the exclusive supplier for the Atlin community for 72 continuous hours; and

(d) the Seller is not in material default under any Permit, this EPA or the Interconnection Agreement.

Subject to subsection 5.5(a), the Seller shall cause the Seller's Plant to be operated to demonstrate compliance with subsection 5.2(c) as soon as the Seller's Plant is capable of generating Electricity in the manner specified in that subsection. The Seller and BC HYDRO shall provide all reasonable cooperation to each other so as to schedule the test period referred to in subsection 5.2(c) at a time when the Seller's Plant and BC HYDRO's Atlin distribution system are operating normally. Except as provided in the following sentence, if the requirements of subsection 5.2(c) have not been satisfied for any reason, whether due to Force Majeure, Forced Outage, or other cause whatsoever, the parties will reschedule the test and reperform the test from time to time thereafter at the earliest praticable time or times. If the Seller's Plant did not generate Electricity for 72 continuous hours as provided in subsection 5.2(c) solely due to the inability of BC HYDRO's Plant to accept delivery of Electricity due to one or more Outages affecting BC HYDRO's Plant for a period (individually or in the aggregate) not exceeding 1 hour during such 72 hour period, the Seller's Plant shall nevertheless be deemed to have satisfied the requirements of subsection 5.2(c).

BC HYDRO may have its representatives present at the Seller's Plant to observe the commissioning and testing of the Seller's Plant. The Seller shall provide reasonable advance notice to BC HYDRO of material commissioning and testing activities.

5.3 **Notice of COD** - Subject to subsection 5.5(a), when the Seller believes that COD has occurred, the Seller shall give BC HYDRO prompt notice together with copies of all Permits, and material required to demonstrate that the Seller's Plant has complied with the requirements of subsection 5.2(c). BC HYDRO shall promptly acknowledge receipt of such notice and advise the Seller whether or not BC HYDRO agrees that COD has occurred.

5.4 **Deposit** - The Seller has paid on execution and delivery of this EPA by it, and BC HYDRO is holding, a deposit in the amount of $15,000. BC HYDRO shall refund that deposit to the Seller, without interest, within 30 days after COD. If this EPA is terminated by either Party prior to COD, other than due to a breach of the EPA by BC HYDRO or termination under section 3.3, then BC HYDRO may retain the deposit without limiting any other remedies BC HYDRO may have.

5.5 **Acceleration/Delay of COD**

(a) Notwithstanding Section 5.2, COD cannot occur more than 90 days prior to the Target COD, without the prior consent of BC HYDRO. If the conditions for COD in Section 5.2 are satisfied more than 90 days prior to the Target COD, COD will occur on the date that is 90 days prior to the Target COD, provided that the conditions in Section 5.2 continue to be satisfied at that date.

(b) If COD does not occur by the date that is 365 days after Target COD, plus the number of days, not exceeding a further 365, during which COD is delayed due to Force Majeure invoked by the Seller in accordance with Section 10, BC

HYDRO may terminate this EPA at any time prior to COD by notice to the Seller, in which case the provisions of Section 15.3 will apply.

6. SELLER'S PLANT AND ELECTRICAL SYSTEMS

6.1 **Seller's Plant** - The Seller shall cause the Seller's Plant to be located and constructed in accordance with the description in Appendix 3. The Seller's Plant will be owned by the Seller, and operated by the Seller using qualified and experienced persons who are employees of the Seller or of the Seller's contract operator. The Seller shall design, construct, interconnect to the BC HYDRO's Plant, commission, operate and maintain the Seller's Plant in compliance with applicable laws, the terms and conditions of all Permits and land tenure agreements issued to the Seller in connection with the Seller's Plant, Good Utility Practice, and the terms and conditions of this EPA and the Interconnection Agreement. Subject to Force Majeure, Outages of BC HYDRO's Plant, Outages of the Seller's Plant where there is no breach by the Seller of this EPA, Permit restrictions and availability of Energy Source (provided that cost will not be a factor in determining the availability of the Energy Source), the Seller shall at all times during the Term operate the Seller's Plant so as to supply the Electricity requirements of BC HYDRO for the purpose of supplying customers in the community of Atlin, unless BC HYDRO gives its consent to reduced generation.

6.2 **Notice of Forced Outages and Maintenance Outages** - The Seller shall promptly notify BC HYDRO of any Forced Outage or Maintenance Outage of the Seller's Plant.

6.3 **Planned Outages** - The Seller shall give BC HYDRO not less than 180 days prior notice of a Planned Outage where such Planned Outage involves major maintenance of the Seller's Plant. The Seller shall make reasonable efforts to coordinate all Planned Outages with BC HYDRO's requirements. BC HYDRO may require the Seller to reschedule any Planned Outage, provided that the rescheduling is consistent with Good Utility Practice and does not have a material adverse financial effect on the operation of the Seller's Plant.

6.4 **Modification to Seller's Plant** - The Seller shall not, without BC HYDRO's prior consent, make any modification or addition to the Seller's Plant which is likely to have a materially adverse effect on the quality or reliability of Delivered Electricity or on the attributes or value of any Green Rights or Emission Credits retained or acquired by BC HYDRO hereunder as referred to in section 8.8.

7. SUSPENSION

7.1 **Suspension**

(a) Subject to subsection 7.1(b), BC HYDRO may refuse to accept delivery of Electricity from the Seller if the Seller is in material default under this EPA or the Interconnection Agreement.

(b) The right of BC HYDRO to refuse to accept deliveries of Electricity under subsection 7.1(a) is subject to:

(i) BC HYDRO giving the Seller notice of BC HYDRO's intent to refuse to accept deliveries; and

(ii) within 30 days after such notice the Seller having failed to cure to the satisfaction of BC HYDRO, acting reasonably, the cause of the proposed suspension, provided that if the Seller is working diligently to cure the cause and if the cause cannot reasonably be cured within the 30 day notice period, then after expiry of a reasonable time to cure the cause.

(c) BC HYDRO is not required to pay the Seller for any Delivered Electricity, or any Electricity capable of being generated during any period, when BC HYDRO has suspended accepting deliveries of Electricity in accordance with this Article 7.

7.2 **Resuming Deliveries** - BC HYDRO will resume accepting deliveries of Electricity when the Seller has demonstrated to BC HYDRO, acting reasonably, that the Seller has cured the cause for the suspension under Section 7.1, and the Seller will resume delivering Electricity to BC HYDRO at that time.

7.3 **Termination for Extended Suspension** - BC HYDRO may terminate this EPA by notice to the Seller if a suspension under Section 7.1 continues for more than 365 days from the date of commencement of the suspension. If BC HYDRO terminates this EPA under this Section 7.3, Section 15.3 applies.

8. PURCHASE AND SALE OF ELECTRICITY

8.1 **Sale and Purchase of Electricity** - Subject to Section 8.5, during the period between COD and the end of the Term, the Seller shall use its best efforts to deliver Electricity in each calendar year up to the Seller's Maximum Delivery Obligation for that calendar year as set forth in section 2.1 of Appendix 2 (including any amendments thereto) to the Point of Delivery for sale to BC HYDRO, and, subject to section 8.3(b), BC HYDRO shall purchase and accept delivery at the Point of Delivery of all Delivered Electricity. In the event that COD occurs on a day other than January 1 in any calendar year, such that each Year of the Term commences and ends on dates other than calendar year dates, the Seller's Maximum Delivery Obligation for the part calendar years at the commencement of the Term and at the end of the Term shall be prorated in accordance with the monthly percentages set forth in Section 3 of Appendix 3.

8.2 **Minimum Sale and Purchase Obligations** - The parties acknowledge and agree that the viability of the Project and the economic benefits expected to be derived by each party under this EPA have been determined on the basis of the Forecast Load for the

community of Atlin for each calendar year as set forth in section 2.1 of Appendix 2. Accordingly, subject to the "carry forward / carry back" adjustments provided for in section 8.2(c), the Seller agrees to sell and deliver, and BC HYDRO agrees to purchase and accept delivery of, at least the minimum amounts of Electricity set forth hereafter:

(a) The Seller shall generate and deliver to the Point of Delivery in each calendar year at least the Seller's Minimum Delivery Obligation, being either ninety per cent (90%) of the Forecast Load for that calendar year as set forth in section 2.1 of Appendix 2, or ninety percent (90%) of the actual total Electricity requirements for the community of Atlin for that calendar year, whichever is the lesser. However, if the Seller is ready and able to deliver Electricity during any period and BC HYDRO's Plant is, for any reason, unable to accept delivery of Electricity during such period, the Seller shall nevertheless be deemed to have satisfied its minimum delivery obligation during such period to the extent it would have delivered Electricity but for the inability of BC HYDRO's Plant to accept delivery.

(b) BC HYDRO will purchase and accept delivery of Electricity at the Point of Delivery in each calendar year at least the amount of Electricity that is equal to the Forecast Load for that calendar year as shown in section 2.1 of Appendix 2. However, if BC Hydro is ready and able to accept delivery of Electricity during any period and the Seller is, for any reason, unable to deliver Electricity during such period, then BC HYDRO shall nevertheless be deemed to have satisfied its minimum purchase obligation during such period to the extent it would accepted delivery of Electricity but for the inability of the Seller's Plant to make delivery.

(c) For the purpose of determining compliance with Section 8.2(a) and 8.2(b) by the Seller and BC HYDRO respectively for a given calendar year, a "carry forward / carry back" adjustment will be made so as to take into account any excess generation by the Seller or taking of Electricity by BC HYDRO for the year prior to and the year following the year in question. That is, if the Seller generated and delivered Electricity in excess of the minimum requirement set forth in section 8.2(a) in the prior year, the amount of the excess will be applied to offset any shortfall in the year in question; and further, any excess in the year following will also be applied (to the extent required) to offset any remaining shortfall in the year in question. Similarly, any excess taking of Electricity by BC HYDRO above the minimum requirement set forth in Section 8.2(b) in the prior year and in the following year, will be applied in the same manner to offset any shortfall by BC HYDRO in the year in question.

(d) If despite the application of excess amounts as provided in section 8.2(c), there still remains a shortfall in the generation and delivery of Electricity by the Seller or the taking of Electricity by BC Hydro for the year in question (excepting in the case of the Seller, any shortfalls in generation and delivery or

taking of Electricity resulting from Force Majeure or Forced Outage, and in the case of BC HYDRO, any shortfalls in the taking of Electricity resulting from Force Majeure), the Seller or BC Hydro, as the case may be, shall pay a compensating amount to the other, as follows:

(i) In the case of the Seller, the compensating amount shall be determined by multiplying the amount of the shortfall in kW.h times the amount per kW.h set forth in the table in section 4.1 of Appendix 2;, and

(ii) In the case of BC HYDRO, the compensating amount shall be determined by multiplying the amount of the shortfall in kW.h times the Tier 1 Energy Price as set forth in Appendix 2 that was payable by BC Hydro for Electricity in December of the calendar year in which the shortfall occurred.

8.3 **Priority of Electricity Supply** - It is agreed that BC HYDRO shall at all times during each calendar year of the Term have first priority to the supply of Electricity from the Seller's Plant up to the amount of the Seller's Maximum Delivery Obligation set forth in section 2.1 of Appendix 2. The Seller shall not, without BC HYDRO's prior consent (such consent not to be unreasonably withheld or delayed by BC HYDRO) sell or commit to sell Electricity to any third party if the effect of such sale or commitment to sell would derogate from the first priority given to BC HYDRO by the preceding sentence. For these purposes the Seller's Maximum Delivery Obligation shall be prorated on a monthly basis, using the monthly percentages set forth in Table 1 of Appendix 3, for the period during which any sale or commitment to sell Electricity to a third party would remain in effect.

8.4 **Disposition of Surplus Electricity** – If the Seller intends to sell Electricity to any party other than BC HYDRO as permitted under this EPA, the Seller, at its cost, shall obtain all permits, licenses and other approvals of any government or governmental agency, including regulatory approvals, all additional interconnection facilities, all additional metering facilities, all interconnection agreements, and all transmission facilities or services, including wheeling agreements, required to enable it to lawfully generate sell and deliver Electricity to such third parties. The Seller shall not take, or omit to take, any action that would cause the Seller to cease to be exempt from regulation as a "public utility", as defined in the UCA, at any time during the Term.

8.5 **Custody, Control and Risk of Electricity** - Custody, control and risk of, and title to, Electricity will pass from the Seller to BC HYDRO at the Point of Delivery.

8.6 **Limitations**

(a) The obligations of the Seller under Section 8.1 are subject to:

(i) Force Majeure invoked by the Seller in accordance with Article 10;

(ii) disconnection of the Seller's Plant by BC HYDRO – Distribution pursuant to the Interconnection Agreement for reasons that are not attributable to the Seller; and

(iii) Outages of BC HYDRO'S Plant except to the extent otherwise provided in Section 8.7.

(b) The obligations of BC HYDRO under Section 8.1 are subject to:

(i) Force Majeure invoked by BC HYDRO in accordance with Article 10;

(ii) the right of BC HYDRO to disconnect the Seller's Plant pursuant to the Interconnection Agreement;

(iii) the right of BC HYDRO to refuse to accept deliveries of Electricity from the Seller in accordance with Article 7; and

(iv) Outages of BC HYDRO's Plant except to the extent otherwise provided in Section 8.7.

Without limiting the foregoing, BC HYDRO has no obligation to pay for any Electricity generated, or capable of being generated, while the Seller's Plant has been disconnected by BC HYDRO pursuant to the Interconnection Agreement.

8.7 **Price and Deemed Deliveries** - BC HYDRO shall pay for Delivered Electricity at the prices specified in Appendix 2, which prices include full and total payment and consideration for the acquisition or retention by BC HYDRO of all Green Rights and Emission Credits pursuant to Section 8.8. If during any calendar month after COD the Seller is unable to deliver Electricity at the Point of Delivery due to an Outage or Outages of BC HYDRO's Plant, exceeding in the aggregate 24 hours, whether or not continuous, in that month, other than an Outage attributable to the Seller or the Seller's Plant, then the quantity of electricity that could have been generated and delivered at the Point of Delivery after such 24 hours has elapsed and during the balance of that Outage, had the Outage not occurred, but having regard to all other conditions prevailing during the Outage, will be deemed to be Delivered Electricity for the purpose of this Section 8.7. The amount of Electricity deemed to have been delivered in accordance with the foregoing shall be determined by (i) reference to the amount of Electricity delivered to the Point of Delivery during the 72 hour period of operation of the Seller's Plant prior to the Outage, if such deliveries are or would be representative of the Electricity that would have been delivered if the Outage had not occurred, or (ii) by agreement between the Seller and BC HYDRO, or, failing such agreement, by arbitration pursuant to section 20.6.

8.8 **Green Rights and Emission Credits** – The Seller and BC HYDRO agree that BC HYDRO will retain, or acquire from the Seller, at no additional cost to BC HYDRO, and in proportion to the amount of Delivered Electricity taken or deemed to be taken by BC HYDRO pursuant to this EPA in relation to the amount of Electricity delivered

to others as permitted by Section 8.3 hereof, , all right, title, interest and benefit in and to any and all (i) Green Rights, and (ii) Emission Credits. To the extent required to give effect to this Section 8.8, the Seller hereby transfers, assigns and conveys to BC HYDRO any and all such Green Rights and Emission Credits, in the proportion aforesaid. To the extent that the said Green Rights and Emission Credits cannot be lawfully allocated or transferred to more than one party, all such Green Rights and Emission Credits shall be wholly the property of BC HYDRO.

8.9 **Revenue Metering Equipment** - The Seller will, at the Seller's cost, install at the Point of Metering revenue metering equipment which is capable of being remotely interrogated. The Seller will maintain that equipment at the Seller's cost. That equipment will be used for determining the quantity of Delivered Electricity under this EPA. The Seller will ensure that the meter at the Point of Metering is calibrated to measure the quantity of Delivered Electricity at the Point of Delivery. The *Electricity and Gas Inspection Act* (Canada) will govern the metering under this EPA. If at any time BC HYDRO is dissatisfied with the condition or registration of all or part of the Seller's metering equipment or if there is any dispute regarding the accuracy of the Seller's metering equipment, then BC HYDRO may give notice to the Seller of its dissatisfaction or of the dispute, in which case BC HYDRO and the Seller will proceed to rectify the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

9. STATEMENTS AND PAYMENT

9.1 Statements

(a) In each calendar month after the calendar month in which Electricity is first delivered to BC HYDRO, the Seller, at its convenience, will deliver to BC HYDRO a statement prepared by the Seller for the preceding calendar month. The statement must indicate the amount of Delivered Electricity, and the amount payable by BC HYDRO for that Delivered Electricity pursuant to Appendix 2, and set out in reasonable detail the manner by which the statement and the amount payable by BC HYDRO was computed. The statement must be accompanied by sufficient data to enable BC HYDRO, acting reasonably, to satisfy itself as to the accuracy of the statement. The data must include a reading of the Metering Equipment read locally or interrogated remotely by electronic means.

(b) Either Party may advise the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts advised within the 36 month period, which will be resolved in accordance with this EPA.

9.2 **Payment**

(a) Within 30 days after receipt of a statement delivered pursuant to subsection 9.1(a), BC HYDRO shall pay to the Seller the amount set out in the statement. If BC HYDRO disputes any portion of the amount, it must nevertheless pay the undisputed portion.

(b) BC HYDRO may dispute all or part of a statement by notice to the Seller in compliance with subsection 9.1(b). The Seller may dispute the amount paid by notice to BC HYDRO, in accordance with subsection 9.1(b).

(c) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 3% until the amount is paid.

9.3 **GST and PST** - All dollar amounts in this EPA do not include GST and PST, which, if applicable, will be added to each statement.

10. FORCE MAJEURE

10.1 **Invoking Force Majeure and Notice**

(a) Neither Party will be in default as to any obligation under this EPA if that Party is unable to perform that obligation due to an event or circumstance of Force Majeure, of which notice is given as required in this Section 10.1.

(b) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, that Party will promptly notify the other Party of the Force Majeure. The notice must identify the nature of the Force Majeure, its expected duration and the particular obligations affected by the Force Majeure. The affected Party shall provide the other Party reports with respect to the Force Majeure at such intervals as the other Party may reasonably request while the Force Majeure continues. A Party will be deemed to have invoked Force Majeure from the date when that Party gives notice of the Force Majeure in accordance with this subsection 10.1(b). The Party invoking Force Majeure shall give prompt notice of the end of the Force Majeure.

(c) The Party invoking Force Majeure shall use all commercially reasonable efforts, including sourcing goods and services from alternative suppliers or using alternative methods, to remove the Force Majeure as soon as possible, provided that settlement of strikes, lockouts and other labour disturbances will be wholly within the discretion of the Party involved. The Parties acknowledge that the foregoing does not oblige or permit the Seller to provide electricity from any generating source other than the Seller's Plant. The Party invoking Force Majeure shall promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remedy the situation.

10.2 **Exclusions** - A Party may not invoke Force Majeure:

(a) for economic hardship or for lack of money, credit or markets; or

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a permit, certificate, license or approval or of any applicable laws, regulations or orders; or

(c) if the Party seeking to invoke Force Majeure has failed to use all commercially reasonable efforts to prevent or remedy the situation and remove, so far as possible and with reasonable dispatch, the Force Majeure; or

(d) if the event or circumstance relied upon was caused by a default under this EPA by the Party seeking to invoke Force Majeure.

10.3 **Termination for Extended Force Majeure** - A Party receiving a notice from the other Party invoking Force Majeure may terminate this EPA by notice to the other Party if the Force Majeure has not been removed within 365 days after the date of the notice invoking Force Majeure, in which case Section 15.3 applies.

11. ELECTRIC SERVICE TO THE SELLER

If at any time BC HYDRO makes electric service available to the Seller's Plant, then that service will be provided under and in accordance with the BC HYDRO electric tariff applicable at the relevant time, and not under this EPA.

12. INSPECTION

For the sole purpose of verifying compliance with this Agreement, on reasonable prior written notice to the Seller, the Seller shall provide BC HYDRO with prompt access during normal business hours to the Seller's Plant and to the records relating to the Seller's Plant including, Electricity production records and operating logs, relay target reports, maintenance reports, and statement support records. BC HYDRO may take copies of all records relating to the Seller's Plant, all of which are confidential information under Section 20.7. BC HYDRO shall exercise any access under this Section 12 in a manner that minimizes disruption to the operation of the Seller's Plant. Any review, inspection or audit by BC HYDRO of the Seller's Plant, its design, construction, operation, maintenance, repair, records or other activities of the Seller during this EPA may not be relied upon by the Seller, or others, as confirming or approving those matters.

13. INSURANCE

13.1 **Insurance** - The Seller shall place and maintain commercial general liability insurance with a limit of not less than $3,000,000 for any one occurrence from the commencement of construction work on the site of the Seller's Plant and for the Term of this EPA.

13.2 **Insurance Provisions** - Commercial general liability policies must include BC HYDRO, its directors, officers, employees and agents as additional insureds and must contain a severability of interest clause. The Seller shall give BC HYDRO a copy of the insurance certificate for each policy required to be maintained by the Seller under this Article 13.

14. ASSIGNMENT

14.1 **Assignment** - A Party may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term except:

(a) with the consent of the other Party, such consent not to be unreasonably withheld or delayed, or

(b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignee to the other Party not less than 35 days before the date of assignment, and, except in the case of assignment to a lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 14.1(a), other than to a lender, evidence of the capability of the assignee as required by subsection 14.2(b). If the consent of the other Party to an assignment, other than to a lender, is required hereunder, the other Party shall give its consent, or notice of the withholding of consent accompanied by written reasons therefor, within 28 days after receipt of the foregoing notice, request and evidence, as applicable, failing which such consent is deemed to be given. Consent to an assignment to a lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by Section 14.3. Any sale or other disposition of all or a substantial part of the Seller's Plant, or of all or any interest in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Project Assets and any change of control, merger, amalgamation or reorganization of the Seller is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 14, including without limitation, Section 14.2.

14.2 **Preconditions to Assignment** - Without limiting subsection 14.1(a), any assignment pursuant to Section 14.1 (other than an assignment to a lender) is subject to:

(a) the assignee entering into and becoming bound by this EPA and assuming all the obligations and liabilities of the assignor under the EPA arising both before and after the assignment of the EPA;

(b) except for an assignment under subsections 14.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial and

otherwise) to fulfill the obligations of the assignor under this EPA, and upon such demonstration and concurrently with the agreement required under subsection 14.2(a), the assignor shall be released from all future obligations and liabilities under the EPA; and

(c) except for an assignment under subsections 14.1(b), the other Party, acting reasonably, being satisfied that the proposed assignment would have no material adverse impact on it or its business or reputation.

14.3 **Assignment to Lender** - If the Seller intends to assign this EPA to a lender or lenders, the Seller acknowledges that BC HYDRO is entitled to require, as a condition of BC HYDRO's consent to such assignment, that the Seller and the lender enter into an agreement with BC HYDRO with respect to the terms on which BC HYDRO will provide its consent, and the relative priorities of any security given to the lender and BC HYDRO. BC HYDRO agrees to negotiate the terms of such agreement in good faith and in a commercially reasonable manner. For greater clarity any security granted to the Facility Lender by the Seller with respect to the Seller's Plant and any right to construct and operate the Seller's Plant, including the Resources, that the Facility Lender may have in relation to its security or otherwise, will have priority and precedence over any security granted by the Seller to BC HYDRO and any right BC HYDRO may have in relation to such security or otherwise to construct and operate the Seller's Plant including the Resources.

14.4 **Costs** - The assignor shall reimburse the other Party for all costs reasonably incurred in connection with an assignment.

14.5 **No Assignment Before COD** - The Seller shall not assign or otherwise dispose of any interest in this EPA prior to COD, except (i) to an Affiliate as permitted under subsection 14.1(b), or (ii) to a lender as permitted under subsection 14.1(a) and Section 14.3, or (iii) with the prior consent of BC HYDRO.

15. TERMINATION

15.1 **Termination for Bankruptcy/Insolvency or Default** - A Party may terminate this EPA by notice to the other Party if:

(a) the other Party is Bankrupt or Insolvent and that termination will be effective immediately upon notice to the other Party; or

(b) except where an amount has been disputed in the manner specified in subsection 9.1(b), an amount due and payable by the other Party to the terminating Party under this EPA remains unpaid for 60 days after its due date, and that termination will be effective upon 30 days notice to the other Party, unless the other Party makes payment in full within that 30 day notice period; or

(c) the other Party is in material default of any of its covenants, representations

and warranties or other obligations under this EPA (other than as provided in subsection 15.1(b)), and that termination will be effective upon 30 days notice to the other Party, unless the other Party cures the default within that 30 day notice period or, if the default cannot be cured within that notice period, and the other Party is working diligently to cure the default, then after expiry of a reasonable time to cure the default.

15.2 **Termination by BC HYDRO** - BC HYDRO may terminate this EPA at any time by notice to the Seller if:

(a) the Interconnection Agreement is terminated; or

(b) the Seller's Plant is disconnected from BC HYDRO's Plant under the Interconnection Agreement for reasons attributable to the Seller more than twice or for a period of more than 360 hours in aggregate duration (whether or not continuous) in any continuous period of 365 days;

and that termination will be effective upon 30 days notice to the Seller, unless, in the case of termination under subsection 15.2(a), a new Interconnection Agreement is entered into between the Seller and BC HYDRO within that 30 day period or, in the case of termination under subsection 15.2(b), the Seller has cured the cause of the disconnection within that 30 day period or where the cause cannot be cured within that 30 day period, and the Seller is working diligently to cure the cause, then after expiry of a reasonable time to cure the cause.

15.3 **Effect of Termination** - If this EPA is terminated pursuant to Article 3, Section 5.5, Section 7.3, Section 10.4 or Article 15:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of the EPA, subject to any express limitations or exclusions of liability set out in this EPA; and

(b) the Parties will remain bound by Sections 20.6 and 20.7 and the Seller will remain bound by Section 3.3 and Article 19 and, for a period of 36 months following termination of this EPA, Section 12 and by any other provisions necessary for the interpretation and enforcement of those provisions.

15.4 **Limitation on Liability** –Except as expressly set out in this EPA, the Seller will not be liable for any losses, damages, costs, expenses and liabilities including special, indirect or consequential damages resulting from any failure by it to deliver electricity to BC Hydro in accordance with this EPA and for greater clarity, any costs and expenses BC Hydro incurs to provide electricity other than from the Seller's Plant to BC Hydro's customers.

16. STEP-IN RIGHTS TO PERMIT BC HYDRO TO CONSTRUCT AND OPERATE

16.1 **Construction and Operation by BC HYDRO** - Upon the occurrence of any event giving rise to a right of BC HYDRO to terminate this EPA pursuant to section 15.1 or 15.2 , BC HYDRO may by notice to the Seller, with a copy to each Facility Lender with whom BC HYDRO has entered into a consent agreement pursuant to section 14.3, declare its right to terminate this EPA, and subject to any such consent agreement BC HYDRO may, but is not obliged to, in addition to any other remedies it may have hereunder or any other contract documents or at law, enter upon the Seller's Plant and take over the construction and/or operation of the Seller's Plant, and take over direction of the Seller's Plant, its employees, management, and related equipment, materials, goods and other resources (collectively, the "Resources") as are intended or proposed to be used in the construction and/or operation of the Seller's Plant. BC HYDRO may take possession and have use of the Seller's Plant and all Resources for construction and/or operation of the Seller's Plant, and may construct and/or operate the Seller's Plant itself, or, at its option, may cause the construction and/or operation of the Seller's Plant to be provided by any other persons or firm whom it may choose to employ, using in so doing, at its option, such of the said Resources as it or such person or firm shall think fit, and it and any such person or firm shall at their option be entitled to remain in the Seller's Plant with employees and others, and to take over direction (and, if necessary, payment) of such of the Seller's employees as may be necessary to construct and/or operate the Seller's Plant, but such employees shall at all times remain employees of the Seller. BC HYDRO agrees to pay to the Seller a reasonable fee for use of the Resources for such time as BC HYDRO makes use thereof. BC HYDRO and the Seller agree to negotiate such fee in good faith and in a commercially reasonable manner. The Seller shall not grant any Person, other than the Facility Lender (as defined in section 17.2), a right to possess, assume control of and carry out construction and/or operation of the Seller's Plant that is equal, or superior, to BC HYDRO's right under this Section 16.1.

16.2 **Appointment As Agent** - The Seller hereby irrevocably appoints BC HYDRO as the Seller's agent for the exclusive purpose of executing such documents and taking such other actions as BC HYDRO may reasonably deem necessary or appropriate to exercise BC HYDRO's rights pursuant to this Article 16.

16.3 **Power of Attorney** - The Seller hereby irrevocably grants to BC HYDRO a power of attorney to carry out all acts, and to execute all documents, as BC HYDRO may reasonably deem necessary or appropriate to exercise BC HYDRO's rights pursuant to this Article 16. BC HYDRO shall not exercise such power of attorney until the occurrence of an event giving rise to a right of BC HYDRO to terminate this EPA pursuant to section 15.1 or 15.2 and until BC HYDRO has given the Seller notice in accordance with Section 16.4.

16.4 **Notice** - BC HYDRO shall give the Seller and the Facility Lender 10 days' prior notice of the contemplated exercise of BC HYDRO's rights under Section 16.1. Upon

receipt of such notice, the Seller shall within 10 days after the date of delivery of such notice collect and have available at a convenient, central location at the Seller's Plant all documents, contracts, books, manuals, reports, records and Permits required to construct, operate and maintain the Seller's Plant in accordance with Good Electric Industry Practice. From the date that is 10 days after the date of delivery of notice pursuant to this Section 16.4, BC HYDRO, its employees, contractors or designated third parties shall have the unrestricted right to enter the Seller's Plant for the purpose of constructing and/or operating the Seller's Plant.

16.5 **Reimbursement of Costs -** The Seller shall within 15 days after the date of delivery of an invoice from BC HYDRO to the Seller reimburse BC HYDRO for any expenses reasonably incurred by BC HYDRO in exercising its rights under this Article 16. If the Seller fails to pay any amount owing by the Seller to BC HYDRO pursuant to this Section 16.5, in addition to the rights provided to BC HYDRO herein, BC HYDRO shall be entitled to draw or realize on any security provided to BC HYDRO under this agreement in such amount, and if BC HYDRO draws any cash security or letter of credit security the Seller shall promptly replenish or restore such security.

16.6 **Proceeds** - During any period that BC HYDRO is in possession of, and constructing and/or operating, the Seller's Plant pursuant to this Article 16, BC HYDRO shall continue to comply with its payment obligations under this EPA provided that BC HYDRO shall be entitled to deduct from any amounts owing by BC HYDRO to the Seller pursuant to the EPA any and all expenses reasonably incurred by BC HYDRO in taking possession of and constructing and operating the Seller's Plant and shall thereafter remit any remaining proceeds to the Seller.

16.7 **Title -** During any period that BC HYDRO is in possession of, and constructing and/or operating, the Seller's Plant pursuant to this Article 16 the Seller shall retain legal title to, and ownership of, the Seller's Plant and all related equipment, materials, goods and other resources, the Seller shall remain the employer of all employees and management employed by the Seller immediately prior to BC HYDRO taking possession of the Seller's Plant and BC HYDRO shall assume possession, operation and control solely as agent for the Seller without liability as a mortgagee in possession, or otherwise, which the Seller waives any right to claim.

16.8 **Resumption of Control** - The Seller may resume construction and/or operation of the Seller's Plant and BC HYDRO shall relinquish its right to construct and/or operate the Seller's Plant when the Seller demonstrates to BC HYDRO's reasonable satisfaction that it will remove those grounds that originally gave rise to BC HYDRO's rights pursuant to this Article 16 in that the Seller will resume construction and/or operation of the Seller's Plant in accordance with the provisions of this EPA and has cured, or within a reasonable period of time will cure, any grounds for termination pursuant to Article 15 which allowed BC HYDRO to exercise its rights under this Article 16. BC HYDRO agrees to return the Resources in its possession or control to the Seller in the same condition (reasonable wear and tear accepted) as when BC HYDRO exercised its rights pursuant to this Article 16.

16.9 **Liability** - BC HYDRO's exercise of its rights hereunder to possess and construct and/or operate the Seller's Plant and take control of other Resources shall not be deemed to be an assumption by BC HYDRO of any of the Seller's liabilities or obligations, nor shall BC HYDRO be considered for any purpose a mortgagee in possession. If at any time after exercising its rights to take possession of, and construct and/or operate, the Seller's Plant, BC HYDRO elects to return possession of the Seller's Plant and other Resources to the Seller, BC HYDRO shall provide the Seller with at least 15 days prior notice of the date BC HYDRO intends to return such possession and upon receipt of such notice the Seller shall take all measures necessary to resume possession of the Seller's Plant on the date specified in the notice from BC HYDRO.

16.10 **BC HYDRO's Obligation** - If BC HYDRO assumes construction and/or operation of the Seller's Plant under this Article 16, BC HYDRO shall construct and/or operate the Seller's Plant in accordance with Good Electric Industry Practice. If BC HYDRO becomes obligated to return possession of the Seller's Plant to the Seller, or to relinquish possession of the Seller's Plant to the Facility Lender, as provided in this Article 16, BC HYDRO will deliver up the structures, equipment and apparatus comprising the Seller's Plant over which BC HYDRO took control, materially in the same condition as when BC HYDRO took possession (ordinary wear and tear, and damage or destruction by reason of Force Majeure excepted).

16.11 **BC HYDRO Services Only** – The rights and remedies provided in this Article 16 shall apply only to the generation of electricity or the sale thereof to BC HYDRO, and shall not in any way impact upon or effect services or electrical sales which may be provided by the Seller to any other customer or entity.

17. SECURITY FOR SELLER PERFORMANCE

17.1 **Mortgage and General Security Agreement** - By not later than 60 days after the Effective Date, the Seller shall execute and record a mortgage and a general security agreement in respect of the Seller's Plant in the form attached hereto as Appendix 4 and Appendix 5 respectively or in such other form as is reasonably acceptable to BC HYDRO (collectively, the "Security"). The Security shall be given to secure the Seller's continuing performance of all its obligations (including without limitation BC HYDRO's rights pursuant to Article 16) under, and any amounts that may be owed by the Seller to BC HYDRO pursuant to, this EPA, including any damages for failure to perform its obligations hereunder.

17.2 **Perfection of Security** - The Parties shall confirm, define and perfect the Security by executing, filing, registering and recording at the expense of the Seller the Security and such financing statements in respect thereof as BC HYDRO may require. The Seller shall take such further action and execute such further instruments as BC HYDRO shall reasonably require to confirm and continue the validity, priority, and perfection of the Security.

17.3 **Rights Under EPA Not Affected** - The granting of the Security shall not be to the exclusion of, nor be construed to limit, the amount of any other security or any further claims, causes of action or other rights accruing to BC HYDRO by reason of any breach or default by the Seller under this EPA or the early termination of this EPA as provided for herein.

17.4 **Enforcement and Discharge of Security** - The Seller shall reimburse BC HYDRO for the direct expenses (including, without limitation, the reasonable fees and expenses of legal counsel) reasonably incurred by BC HYDRO in connection with the enforcement of the Security and any other documents evidencing the Security. The Security shall be discharged and released, and BC HYDRO shall take any steps reasonably required by the Seller to effect and record such discharge and release, upon the expiry of the Term of this EPA or upon termination of this EPA pursuant to Article 15 or Section 3.1 and in either case upon satisfaction by the Seller of all outstanding obligations and liabilities of the Seller under this EPA.

17.5 **Priority of EPA** – In the event of any conflict or inconsistency between the terms of the Security and the terms of this EPA, the terms as stated in this EPA shall prevail.

18. SELLER'S REPRESENTATIONS AND WARRANTIES

The Seller hereby represents and warrants to BC HYDRO, and acknowledges that BC HYDRO is relying on those representations and warranties in entering into this EPA, as follows:

(a) Corporate Status - If the Seller is a corporation, the Seller is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) Bankruptcy - No actions have been taken or authorized by the Seller or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller;

(c) No Litigation - The Seller is not subject to any order, judgment or decree, litigation, investigation or proceeding, or claim which would interfere with the ability of the Seller to comply with this EPA and no facts, circumstances or conditions exist which might reasonably give rise to such claim, investigations, proceedings or litigation;

(d) Assets - There is no appropriation, expropriation or seizure of any of the assets of the Seller pending or threatened;

(e) No Conflict - Neither the signing of this EPA nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the memorandum or articles of incorporation or bylaws of the Seller, any permit, franchise, lease, license, approval or agreement to which the Seller is a party, or any other covenant or obligation binding on the Seller or affecting any of its properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction and operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(f) Binding Obligation - This EPA constitutes a valid and binding obligation of the Seller enforceable against the Seller in accordance with its terms;

(g) Authorization, Execution and Delivery - This EPA has been duly authorized, executed and delivered by the Seller; and

(h) Seller's Proposal - All material information in the Seller's Proposal is true and correct and there is no material information omitted from the Seller's Proposal, which would make the information in the Seller's Proposal misleading or inaccurate.

19. INDEMNITY

The Seller shall indemnify, defend and hold BC HYDRO and its shareholder(s), directors, officers, employees, agents, representatives, successors and permitted assigns (the "Indemnified Parties") harmless from and against all losses, damages, costs, expenses, liabilities, actions, causes of action, demands, proceedings, claims, expenses, orders, fines and penalties (including all reasonable legal fees and expenses on a solicitor and own client basis) which any of the Indemnified Parties suffer, incur, or are subject to or liable for, as a result of any act or omission (whether negligent or not) of the Seller, any of its Affiliates or their employees, agents or contractors in connection with the design, construction, interconnection to BC HYDRO's Plant, commissioning, financing, operation, maintenance, modification, repair, decommissioning, closure or otherwise of the Seller's Plant, except to the extent caused by the negligence of BC HYDRO or the breach of this EPA by BC HYDRO or the failure by BC Hydro to deliver electricity to its customers in accordance with its approved customer tariff for Atlin and vicinity.

20. GENERAL PROVISIONS

20.1 **Independence** - The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

20.2 **Enurement** - This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

20.3 **Notices** - Any notice, consent, waiver, request, statement or bill (a "notice") that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address stated in subsection 20.3(c) or (d); and:

(a) may be delivered by hand or by a courier service during normal business hours on a Business Day, in which case the notice will be deemed to have been delivered on that Business Day; or

(b) may be sent by facsimile, in which case, if the printed confirmation of transmission indicates the transmission occurred during normal business hours on a Business Day, the notice will be deemed to have been delivered on that Business Day and otherwise the notice will be deemed to have been delivered on the next Business Day after the date of transmission set out in the printed confirmation of transmission.

(c) subject to subsection 20.3(e), the address and FAX number of BC HYDRO for notices is:

Manager, Non-Integrated Areas
6911 Southpoint Drive
Burnaby, B.C.
V3N 4X8
Fax: (604) 528-3220

(d) subject to subsection 20.3(e), the address and FAX number of the Seller for notices is:

Manager, Atlin Hydro Project
Taku Land Corporation
Box 408
Atlin, B.C.
V0W 1A0
Fax: (250) 651-7909

(e) either Party may change its address or FAX number for notices under this EPA by notice to the other Party.

The addressees designated by BC HYDRO and Seller as set forth in sections 20.3 (c) and (d), and any other persons designated in substitution therefor, are in this EPA referred to as "BC HYDRO's Contract Representative" and "Seller's Contract Representative" respectively.

20.4 **Entire Agreement and Amendment** - This EPA contains the entire agreement

between the Parties with respect to the purchase and sale of Electricity. This EPA may not be amended except by an agreement in writing signed by both Parties.

20.5 **No Waiver** - Except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have.

20.6 **Dispute Resolution** - If any dispute arises under or in relation to this EPA, that dispute will be referred to and finally resolved by arbitration by a single arbitrator under the domestic rules of the British Columbia International Commercial Arbitration Centre ("BCICAC"). The arbitration will take place at Vancouver, British Columbia. If at the time a dispute arises the BCICAC does not exist, the dispute will be finally settled by arbitration by a single arbitrator under such rules as the Parties may agree in writing, or failing agreement, by a single arbitrator appointed under the Commercial Arbitration Act (British Columbia) and such rules as that arbitrator may establish or adopt. The arbitrator will have jurisdiction and power to make interim, partial or final awards ordering specific performance, injunction and any other equitable remedy. The Parties are entitled to seek interim measures of protection from the courts pending completion of any arbitration. All performance required under this EPA by the Parties and payments required under this EPA will continue during the dispute resolution proceedings contemplated by this Section 20.6, provided that this Section may not be interpreted or applied to delay or restrict the exercise of any right to suspend performance under or terminate this EPA pursuant to the express terms hereof. Any payments or reimbursements required by an arbitration award will be effective as of the date determined in the award, and, without duplication with subsection 9.2(c), will bear interest at the Prime Rate plus 3%.

20.7 **Confidentiality**

(a) During the term of the EPA and for five years thereafter, each Party shall treat as confidential and will not cause or permit the publication, release or disclosure of all or part of this EPA, any information acquired from the other Party in connection with the settlement of the EPA, or any other information identified herein as confidential ("confidential information"), except to the extent that publication, release or disclosure is necessary to enable a Party to fulfill its obligations under this EPA, is required by law, is made with the prior consent of the other Party, or if such information has entered the public domain other than through the actions of the Party disclosing the information. Nothing in this Section 20.7 shall restrict or prevent BC HYDRO from publishing, releasing or disclosing information relating generally to BC HYDRO's green energy program. The Seller may disclose confidential information to lenders and potential lenders and their employees and advisers in connection with the financing of the Seller's Plant, provided that such disclosure is in accordance with normal lending practices and the lenders and potential lenders to whom

the disclosure is made provide a written, binding undertaking to the Parties to keep the confidential information disclosed to them strictly confidential to the same extent as if they were parties to this EPA. BC HYDRO may disclose confidential information to representatives of the Government of British Columbia who have a need to have knowledge of the confidential information and who have been informed by BC HYDRO of the need to maintain the confidentiality of information disclosed to them.

(b) The Seller acknowledges that BC HYDRO is subject to the *Freedom of Information and Protection of Privacy Act* (British Columbia) and agrees that BC HYDRO's non-disclosure obligations under this EPA may be subject to the provisions of that legislation.

(c) The Parties acknowledge that confidential information constitutes commercial and financial information of the Seller and BC HYDRO, which has been supplied in confidence and the disclosure of which could reasonably be expected to harm significantly the competitive position and/or interfere significantly with the negotiating position of the Seller and further could reasonably be expected to harm the financial or economic interests of BC HYDRO. Accordingly, the Parties confirm their intention that all confidential information disclosed to each other shall be deemed to be confidential and exempt from disclosure to third persons in accordance with Section 21 of the *Freedom of Information and Protection of Privacy Act* of British Columbia, as amended from time to time.

20.8 **Interconnection Agreement** – Notwithstanding that BC HYDRO Distribution is a business unit of British Columbia Hydro and Power Authority, nothing in the Interconnection Agreement and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent herein expressly provided.

20.9 **Commodity Contract** – This EPA constitutes a commodity contract for the purposes of subsection 65.1(8) of the *Bankruptcy and Insolvency Act* (Canada) and subsection 11.1(1) of the *Companies Creditors Arrangement Act* (Canada)

20.10 **Further Assurances** - Each Party shall, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA.

20.11 **Severability** - Any provision of this EPA, which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

20.12 **Counterparts** – This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[This is page 26 of the Electricity Purchase Agreement dated as of November 21, 2006 relating to the Pine Creek Project for electricity supply to the community of Atlin.]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA as of the date of this EPA.

For **TAKU LAND CORPORATION**

John D Ward
Authorized Representative

John D. Ward, President
Print Name and Office

Nov 21 2006
Date

COPY

For **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY:**

Authorized Representative

Bob Elton, President
Print Name and Office

November 21, 2006
Date

APPENDIX 1

DEFINITIONS

References in an Appendix to a Section or subsection mean a Section or subsection of the EPA agreement, and not an Appendix, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

(a) "**Affiliate**" means, with respect to the Seller, any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller and with respect to BC HYDRO, any Person directly or indirectly Controlled by BC HYDRO.

(b) "**BC HYDRO**" means British Columbia Hydro and Power Authority and its successors and permitted assigns.

(c) "**BC HYDRO – Distribution**" means the division within BC Hydro having responsibility for the installation, operation and maintenance of BC HYDRO'S electrical distribution wires, poles, transformers, switchgear and related facilities.

(d) "**BC HYDRO's Plant**" means the physical plant of BC HYDRO that interconnects, or affects the interconnection, or is affected by the interconnection, with the Seller's Plant.

(e) "**BCUC**" means the British Columbia Utilities Commission.

(f) "**Bankrupt or Insolvent**" means, with respect to a Person: (i) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it; or (ii) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy law; or (iii) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy; or (iv) the Person has voluntarily suspended the transaction of its usual business; or (v) a court has issued an order declaring the Person bankrupt or insolvent.

(g) "**Business Day**" means any calendar day which is not a Saturday, Sunday or other day on which the main branch of Bank of Montreal in Vancouver is not open for business.

(h) "**COD**" means the commercial operation date as determined in accordance with Section 5.2.

(i) "**Control**" of any Person means (i) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or persons performing similar functions, or (ii) ownership of 50% or more of the equity or beneficial interest in that Person, or (iii) the

ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

(j) "**CPI**" means, subject to Section 1.9, the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada.

(k) "**Delivered Electricity**" means (i) Electricity, expressed in MWh, as recorded by the Metering Equipment, delivered by the Seller at the Point of Delivery, which BC HYDRO accepts, or is required to accept, pursuant to Section 8.1, and includes electricity deemed to be Delivered Electricity pursuant to Section 8.7.

(l) "**Electricity**" means electricity generated by the Seller's Plant net of any electricity required to service the Seller's Plant.

(m) "**Emissions Credits**" means all right, title, interest and benefit in and to any credit, reduction right, set-off, allocated pollution right, emission reduction allowance, or other proprietary or contractual right, whether or not tradable, resulting from the actual or assumed displacement of emissions from generating facilities owned or operated by BC HYDRO or from which BC HYDRO or any of its Affiliates purchases electricity, wherever located, as a result of the generation, delivery or purchase of Electricity at or from the Seller's Plant during the Term.

(n) "**Energy Source**" means the source of energy used to generate Electricity at the Seller's Plant, as specified in Appendix 3.

(o) "**Facility Lender**" means a lender who provides financing to the Seller for the construction or operation of the Seller's Plant and who takes security over all or any portion of the Seller's Plant to secure such financing, which financing, together with any other financing secured by the Seller's Plant, does not exceed 90% of the construction cost thereof.

(p) **"Forecast Load"** means the amount of Electricity, for any calendar year of the Term, shown in Column 2 of the table in section 2.1 of Appendix 2 opposite each such calendar year.

(q) "**Force Majeure**" means, subject to the exclusions in Section 10.2, any event or circumstance not within the reasonable control of the Party claiming Force Majeure and includes:

(i) acts of God, including wind, ice and other storms, lightning, floods, earthquakes, volcanic eruptions and landslides;

(ii) strikes, lockouts and other industrial disturbances;

(iii) epidemics, war (whether or not declared), blockades, acts of public enemies, acts of sabotage, civil insurrection, riots and civil disobedience;

(iv) acts or omissions of federal, provincial or local governments or any of their boards or agencies, other than BC HYDRO or entities Controlled by BC HYDRO, including delays in regulatory process, and orders of a regulatory authority or court of competent jurisdiction; and

(v) explosions, fires, or mechanical breakdowns.

(r) "**Forced Outage**" means an Outage which is not a Force Majeure resulting from an unplanned component failure or other condition, which requires under Good Utility Practice within 72 hours, a generator or other component to be removed from service or the load on a generator or reliance on the component to be reduced.

(s) "**Good Utility Practice**" means any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be practices, methods or acts generally accepted in the WSCC region.

(t) "**Green Rights**" means all right, title, interest and benefit in and to any credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradable, resulting from the generation, delivery or purchase of Electricity during the Term.

(u) "**GST**" means the goods and services tax imposed under the Excise Tax Act (Canada) as that Act may be amended or replaced from time to time.

(v) "**Initial Period**" means the period specified in Appendix 3, as extended by written agreement between the Parties.

(w) "**Interconnection Agreement**" means the agreement between the Seller and BC HYDRO setting out the terms and conditions of interconnection of the Seller's Plant to BC HYDRO's Plant, as amended or replaced from time to time.

(x) "**Maintenance Outage**" means an Outage, which is not a Force Majeure, resulting from the removal of a generator or other component from service, or a reduction of load on a generator, in order to perform work on specific components that can be deferred such that it does not constitute a Forced Outage but, in accordance with Good Utility Practice, requires a generator or other component to be removed from service before the next Planned Outage.

(y) "**Material Permits**" means permits, certificates, licenses and other approvals required for the design, construction or operation of the Seller's Plant including environmental approvals other than any permit certificates, licenses or other approvals that are not

required for the commencement of construction and are of such a nature that they can reasonably be expected to be obtained in the ordinary course during construction or thereafter.

(z) "**Metering Equipment**" means the metering equipment described in Section 8.7.

(aa) "**Outage**" means a total or partial suspension of the operation of a Plant.

(bb) "**Party**" means (i) BC HYDRO and its successors and permitted assigns, or (ii) the Seller and its successors and permitted assigns, and "Parties" means both BC HYDRO and the Seller and their respective successors and permitted assigns.

(cc) "**Permits**" means permits, certificates, licenses, and other approvals required for the design, construction or operation of the Seller's Plant, including environmental approvals.

(dd) "**Person**" means an individual, body corporate, firm, partnership, joint venture, legal representative or other legal entity.

(ee) "**Planned Outage**" means an Outage, which is scheduled more than 30 days in advance in accordance with Good Utility Practice for purposes of inspection and/or general overhaul of one or more major equipment groups.

(ff) "**Plant**" means, as the context requires, BC HYDRO's Plant or the Seller's Plant.

(gg) "**Point of Delivery**" means the point at which the Seller's Plant interconnects with BC HYDRO's Plant, as more particularly specified in the Interconnection Agreement.

(hh) "**Point of Metering**" means the point of metering described in Appendix 3.

(ii) "**Post-COD Price**" has the meaning given in Appendix 2.

(jj) "**Prime Rate**" means the floating prime interest rate announced from time to time by Bank of Montreal, Vancouver Main Branch, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

(kk) "**Project Assets**" means the Seller's Plant and all rights, property, assets, equipment, materials and contracts required to construct, operate and maintain the Seller's Plant, whether real or personal and whether tangible or intangible, including equipment and other warranties, Permits, supply and other contracts, the goodwill in and right to use the name by which the Seller's Plant is commonly known, the books, records and accounts with respect to the Seller's Plant, and all land tenure and land tenure agreements with respect to the Seller's Plant.

(ll) "**PST**" means provincial social services or sales taxes and similar or replacement assessments, if any.

(mm) "**Securities**" shall have the meaning given to that term in section 1 of the *Securities Act*, RSBC 1996, c.418.

(nn) "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

(oo) "**Seller's Minimum Delivery Obligation**" means the amount of Electricity, for any calendar year of the Term, that is the lesser of the amount shown in Column 3 of the table in Section 2.1 of Appendix 2, or 90% of the actual total Electricity requirements for the community of Atlin for that calendar year.

(pp) "**Seller's Maximum Delivery Obligation**" means the amount of Electricity, for any calendar year of the Term, shown in Column 4 of the table in section 2.1 of Appendix 2.

(qq) "**Seller's Proposal**" means the submission by the Seller to BC HYDRO dated on or about July 4, 2005 pursuant to which the Seller proposed to enter into this EPA, including all documents and supporting and related information provided by the Seller to BC HYDRO with, or in connection with, such submission, whether concurrently with or after the date of such submission.

(rr) "**Seller's Plant**" means the generating plant, transmission lines and associated facilities and infrastructure of the Seller described in Appendix 3, as modified from time to time as permitted under this EPA, and as required for the generation and delivery of Electricity by the Seller to BC HYDRO at the Point of Delivery.

(ss) "**Target COD**" means the date so specified in Appendix 3, which date is not subject to change under this EPA, whether for Force Majeure or otherwise.

(tt) "**Term**" has the meaning given in Section 2.1.

(uu) "**UCA**" means the *Utilities Commission Act* (British Columbia).

(vv) "**WSCC**" means the Western Systems Coordinating Council or any successor organization of which BC HYDRO is a member.

APPENDIX 2

TARIFF

Part I - Pre-COD Price

1.1 The price payable by BC HYDRO for Delivered Electricity generated prior to COD is the then current lowest energy rate as approved by the BCUC for the Rate Zone II Schedule 1107 residential service. At date of signing the EPA, this rate was 6.33¢/kWh. The price payable for pre-COD Delivered Electricity does not vary with the amount of Delivered Electricity.

Part II – Post-COD Price

2.1 The price payable by BC Hydro for Delivered Electricity generated and delivered after COD is dependent on the amount of Delivered Electricity relative to the Atlin Load Forecast for each calendar year of the Term as set forth in the following table:

Annual Load Forecast

Column 1	Column 2	Column 3	Column 4
Calendar Year	**Forecast Load (kWh)**	**Seller's Minimum Delivery Obligation (kWh)**	**Seller's Maximum Delivery Obligation (kWh)**
2008	4,626,000	4,163,400	5,551,200
2009	4,670,000	4,203,000	5,604,000
2010	4,865,000	4,378,500	5,838,000
2011	5,039,000	4,535,100	6,046,800
2012	5,194,000	4,674,600	6,232,800
2013	5,339,000	4,805,100	6,406,800
2014	5,481,000	4,932,900	6,577,200
2015	5,616,000	5,054,400	6,739,200
2016	5,758,000	5,182,200	6,909,600
2017	5,887,000	5,298,300	7,064,400
2018	6,007,000	5,406,300	7,208,400
2019	6,119,000	5,507,100	7,342,800
2020	6,222,000	5,599,800	7,466,400

2021	6,320,000	5,688,000	7,584,000
2022	6,404,000	5,763,600	7,684,800
2023	6,479,000	5,831,100	7,774,800
2024	6,549,000	5,894,100	7,858,800
2025	6,613,000	5,951,700	7,935,600
2026	6,674,000	6,006,600	8,008,800
2027	6,735,000	6,061,500	8,082,000
2028	6,796,000	6,116,400	8,155,200
2029	6,857,000	6,171,300	8,228,400
2030	6,918,000	6,226,200	8,301,600
2031	6,924,088	6,231,679	8,308,906
2032	6,930,181	6,237,163	8,316,217
2033	6,979,000	7,040,538	7,102,618

Delivered Electricity in any calendar year up and including the amount of the Forecast Load set forth in Column 1 in the above table is referred to as "Tier 1 Energy", and Delivered Electricity in any calendar year in excess the Forecast Load set forth in Column 1 is referred to as "Tier 2 Energy".

2.1.1 Tier 1 Energy Price

2.1.1.1 Subject to adjustment as of January 1 during each calendar Year of the Term, the price for Tier 1 Energy (in ¢/kW.h) payable by BC HYDRO for Tier 1 Delivered Electricity is the sum of the Base Price and the PF Surcharge applicable for that calendar year, calculated as follows:

(a) Base Price:

The Base Price for the Calendar Year starting January 1, 2007 is 31.9798¢/kWh.

The Base Price for subsequent Calendar Years is adjusted every year on January 1 using the following formula:
New Base Price = Old Base Price x [1 + CPI Change x .125]

Where Old Base Price	= The price in effect as of the preceding January 1, after adjusting

	for the CPI Change in accordance with section 3.1.
Where CPI Change	= The CPI Change, as a percentage, determined under section 3.1

By way of example, if the CPI Change is 2% (increase) for the period January 1, 2007 to December 31, 2007, the new Base Price payable by BC Hydro effective as of January 1, 2009 for any Post-COD Tier 1 deliveries of Electricity during that calendar year will be:

Price = 31.9798 x [1 + [2% x .125]
= 32.0597¢/kWh

(b) PF Surcharge

Where PF Surcharge	= The Project Financing Surcharge added to the rate for each Year as follows:	
	Year	PF Surcharge (¢/kW.h)
	1	6.4850
	2	5.7820
	3	4.3170
	4	3.1750
	5	2.3100
	6	1.4050
	7	0.7300
	8 and beyond	0

The PF Surcharge will change as of each anniversary of COD during the first seven (7) years of the Term, so that if COD occurred on November 1, 2008, the PF Surcharge of 6.4850 ¢/kW.h would be in effect for the period November 1, 2008 to October 31, 2009, at which time the PF Surcharge would change to 5.7820 ¢/kW.h as of November 1, 2009, then to 4.3170 ¢/kW.h as of November 1, 2010, and so on for the remainder of the Term. There is to be no CPI Change made to the PF Surcharge

2.1.2 Tier 2 Price

The Tier 2 price is 6.33¢/kWh subject to adjustments described in Part III.

Part III - Adjustments to Post-COD Price

3.2 **Tier 1 CPI Change** – For purposes of determining the Price adjustments under section 2.1.1, the CPI in effect on January 1, 2007 will be recorded. On January 1, 2008 and on each January 1 thereafter during the Term, the increase or decrease in the CPI from that in effect as of January 1 in the preceding year will be recorded. The increase or decrease in the CPI over the preceding calendar year, as a percentage, will be the "CPI Change" for purposes of section 2.1. The base price of 31.9798 ¢/kW.h.which the parties have agreed is applicable as of January 1, 2007 already includes the anticipated CPI increase during 2006, and no adjustment to that price shall be made on account of any CPI change for the period January 1, 2006 to December 31, 2006.

3.2 **Tier 2 Price Change** – The Tier 2 price is the lowest energy price for Schedule 1107 Rate Zone II Residential Service, as may be amended or replaced from time to time by BC Hydro and approved by the BCUC.

Part IV – Compensating Amount Payable by Seller (section 8.2(d))

4.1 The compensating amount payable by the Seller for shortfalls in generation and delivery of Electricity in any calendar year of the Term as set forth in section 8.2(d)(i) of the Agreement, is the amount of the shortfall in kW.h multiplied by the rate set forth in the following table:

Calendar Year	Price per kWH ($/kW.h)
2008	0.047
2009	0.048
2010	0.049
2011	0.050
2012	0.051
2013	0.052
2014	0.053
2015	0.054
2016	0.055
2017	0.056
2018	0.057
2019	0.058
2020	0.060
2021	0.061
2022	0.062
2023	0.063
2024	0.065
2025	0.066
2026	0.067
2027	0.068
2028	0.070
2029	0.071
2030	0.073
2031	0.074
2032	0.076
2033	0.077

Part V - No Further Payments

The amounts payable by BC HYDRO specified in this Appendix 2 are the full and complete payment and consideration payable by BC HYDRO for all Delivered Electricity under this EPA, including all associated Emission Credits and Green Rights.

APPENDIX 3

DESCRIPTION OF SELLER'S PLANT

1. Seller's Plant

General Description: The project is a small 2 MW hydroelectric project on Pine Creek, located approximately 4 km east of the town of Atlin, B.C. Water flows out of Surprise Lake into Pine Creek, which flows about 18 km in a westerly direction into Atlin Lake. The project will comprise a control structure at the outlet of Surprise Lake, an intake weir located 8.3 km upstream of the confluence with Atlin Lake, a powerhouse and tailrace located 4 km from the confluence with Atlin Lake, a transmission line and access roads. The control structure at the outlet of Surprise Lake will release sufficient water to allow the plant to operate at full capacity year round and displace the present diesel generation. A fish ladder will be incorporated into the control structure for migrating Arctic Graylings. The intake weir will divert water from Pine Creek through a 4 km buried penstock to the powerhouse just above the confluence with Spruce Creek. A new, 25kV distribution line will connect with the existing local diesel station substation bus.

Energy Source: Hydropower

2. Key Facilities and Equipment:

- Capacity: 2 MW
- Turbine Type: Turgo Impulse (1 or 2 units)
- Generator Type: 4160V AC 3 phase 2400 kVA total
- Penstock
  - Length: 3981m
  - Diameter: 63" (30m steel), 48" (3695m HDPE), 42" (1615m HDPE, 256m steel)
  - Materials: HDPE (3695m), Steel (286m)
- Control Structure
  - Weir Elevation: 913.15m
  - Lake Elev. Range: 912.05m to 913.85m (at 1 in 36 year daily flow)
  - Average release rate: 2.8 m^3/s (in year 20 assuming 10% MAD for fish release)
- Fish Bypass
  - Elevation range: Greater than 912.25m

Minimum velocity	low
Maximum velocity	1.5 m/s

- Diversion Design Flow 2.45 m^3/s
- Powerhouse

Length	19.1m
Width	15.24m
Height	8.1m
Elevation	725m (approx)

3. **Expected Energy Output:**

Month	Expected % of annual generation
January	11.9
February	9.9
March	10.0
April	8.1
May	6.9
June	6.2
July	6.3
August	6.4
September	7.1
October	7.9
November	9.0
December	10.3
Total	100%

4. **Point of Metering** – At the point of interconnection to the Atlin Diesel Generating Station substation.

5. **Target COD** – 1 April 2008

6. **Initial Period Expiry Date** – 1 April 2007

APPENDIX 4

SAMPLE FORM MORTGAGE

(SECTION 16.1)

LAND TITLE ACT
FORM B
(Section 225)
Province of
British Columbia

MORTGAGE - PART 1 *(This area for Land Title Office use)* PAGE 1 of 4

1. APPLICATION: (Name, address, phone number and signature of applicant, applicant's solicitor or agent)
_____, Borden Ladner Gervais LLP, 1200 - 200 Burrard Street, Vancouver, British Columbia, V7X 1T2, 687-5744

Client No. 10439 (File No. _____)

_____
Signature of Solicitor –

2. PARCEL IDENTIFIER(S) AND LEGAL DESCRIPTION(S) OF THE MORTGAGED LAND:*

(PID)	(LEGAL DESCRIPTION)
[INSERT]	[INSERT]

3. BORROWER(S) [MORTGAGOR(S)]: (including postal address(es) and postal code(s))*

[INSERT]

4. LENDER(S) [MORTGAGEE(S)]: (including occupation(s), postal address(es) and postal code(s))*

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (Inc. No. 0000032) of 333 Dunsmuir Street, Vancouver, B.C. V6B 5R3

5. PAYMENT PROVISIONS:**

			Y	M
(a) Principal Amount: SEE SCHEDULE	(b) Interest Rate: NIL	(c) Interest Adjustment Date: N/A		
(d) Interest Calculation Period: N/A	(e) Payment Dates: N/A	(f) First Payment Date: N/A		
(g) Amount of each periodic payment: N/A	(h) *Interest Act* (Canada) Statement: The equivalent rate of interest calculated half yearly not in advance is _____ % per annum.	(i) Last Payment Date: N/A		
(j) Assignment of Rents which the applicant wants registered? YES | | NO |X| If YES, page and paragraph number:	(k) Place of Payment: POSTAL ADDRESS IN ITEM 4	(l) Balance Due Date: ON DEMAND		

* If space insufficient, enter "SEE SCHEDULE" and attach schedule in Form E.
** If space in any box insufficient, enter "SEE SCHEDULE" and attach schedule in Form E.

Appendix 4 – Sample Form Mortgage

MORTGAGE - PART 1 *(This area for Land Title Office use)* PAGE 2 of 4

6. MORTGAGE contains floating charge on land? YES | | NO |X|

7. MORTGAGE secures a current or running account? YES | | NO |

8. INTEREST MORTGAGED:
Freehold |X|
Other (*specify*) | |*

9. MORTGAGE TERMS:
Part 2 of this mortgage consists of (select one only):
(a) Prescribed Standard Mortgage Terms |X|
(b) Filed Standard Mortgage Terms | |
(c) Express Mortgage Terms | |
D.F. Number:
(annexed to this mortgage as Part 2)
A selection of (a) or (b) includes any additional or modified terms referred to in Item 10 or in a schedule annexed to this mortgage.

10. ADDITIONAL OR MODIFIED TERMS:*
SEE SCHEDULE

11. PRIOR ENCUMBRANCES PERMITTED BY LENDER:*
[INSERT]

12. EXECUTION(S):** This mortgage charges the Borrower's interest in the land mortgaged as security for payment of all money due and performance of all obligations in accordance with the mortgage terms referred to in Item 9 and the Borrower(s) and every other signatory agree(s) to be bound by, and acknowledge(s) receipt of a true copy of, those terms.

Officer Signature(s)	Execution Date Y	M	D	Borrower(s) Signature(s)
Name:				by its authorized signatories: Name: [INSERT] Name: [INSERT]

OFFICER CERTIFICATION:
Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the *Evidence Act*, R.S.B.C. 1996, c. 124, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the *Land Title Act* as they pertain to the execution of this instrument.
* If space insufficient, enter "SEE SCHEDULE" and attach schedule in Form E.
** If space insufficient, continue executions on additional page(s) in Form D.

LAND TITLE ACT
FORM E

SCHEDULE

ENTER THE REQUIRED INFORMATION IN THE SAME ORDER AS THE INFORMATION MUST APPEAR ON THE FREEHOLD TRANSFER FORM, MORTGAGE FORM OR GENERAL DOCUMENT FORM.

5. PAYMENT PROVISIONS:**

(a) Obligation Secured:

The continuing observance and performance of all the borrower's promises and agreements and payment of the mortgage money.

10. ADDITIONAL OR MODIFIED TERMS:*

The Prescribed Standard Mortgage Terms described in Item 9 of Part 1 of Form B are hereby modified as follows:

(a) the definition of "borrower's promises and agreements" set forth in paragraph 1(1) of the Prescribed Standard Mortgage Terms is hereby deleted and the following substituted therefore:

" "borrower's promises and agreements" means any one or more of the borrower's obligations, promises and agreements contained in this mortgage and under the EPA;";

(b) The definition of "mortgage money" set forth in paragraph 1(1) of the Prescribed Standard Mortgage Terms is hereby deleted and the following substituted therefor:

" "mortgage money" means any money that may be owing by the borrower to the lender under this mortgage and pursuant to the EPA, including without limitation any liquidated or other damages due to the lender under the EPA including damages for failure to perform its obligations under the EPA ";

(c) The definition of "principal amount" set forth in paragraph 1(1) of the Prescribed Standard Mortgage Terms is hereby deleted and the following substituted therefor:

""obligation secured" means the continuing observance and performance of the borrower's promises and agreements and payment of the mortgage money;";

(d) Paragraph 1(1) of the Prescribed Standard Mortgage Terms is hereby amended by adding the following definitions thereto:

""EPA" means Electricity Purchase Agreement between the borrower and the lender made as of _____, 2006 and all amendments thereto;";

LAND TITLE ACT
FORM E

SCHEDULE PAGE 4 of 4

ENTER THE REQUIRED INFORMATION IN THE SAME ORDER AS THE INFORMATION MUST APPEAR ON THE FREEHOLD TRANSFER FORM, MORTGAGE FORM OR GENERAL DOCUMENT FORM.

(e) Paragraph 2(1) of the Prescribed Standard Mortgage Terms is hereby deleted and the following substituted therefor:

"In consideration for the lender agreeing to enter the EPA, the borrower grants and mortgages the land to the lender as security for the payment of the mortgage money and for the continuing observance and performance of all the borrower's promises and agreements".

(f) Paragraph 5(1) of the Prescribed Standard Mortgage Terms is hereby amended by adding the new subparagraph (q) as follows:

"(q) if the lender acts to obtain title to the land pursuant to paragraph 8(2)(g), the borrower shall take all steps necessary to transfer all Permits (as defined in EPA) to the lender, and shall diligently prosecute and cooperate in those transfers"

(g) Subparagraph 8(2)(i) of the Prescribed Mortgage Terms is hereby amended by adding the new subparagraph (iv) as follows:

" (iv) operate any building or other plant located on the land."

(h) Paragraph 8(2) of the Prescribed Mortgage Terms is hereby amended

by adding the new subparagraph (k) as follows:

"(k) enter upon the land and take over the construction and/or operation of the borrower's plant on the land, and take over direction of the borrower's plant on the land, its employees, management, and related equipment, materials, goods and other resources (collectively, the "Resources") as are intended or proposed to be used in the construction and/or operation of the borrower's plant on the land. The lender may take possession and have use of the borrower's plant on the land and all Resources for construction and/or operation of the borrower's plant on the land, and may construct and/or operate the land itself, or, at its option, may cause the construction and/or operation of the land to be provided by any other persons or firm whom it may choose to employ, using in so doing, at its option, such of the said Resources as it or such person or firm shall think fit, and it and any such person or firm shall at their option be entitled to remain in the borrower's plant on the land with employees and others, and to take over direction (and, if necessary, payment) of such of the borrower's employees as may be necessary to construct and/or operate the borrower's plant on the land, but such employees shall at all times remain employees of the borrower. The lender agrees to pay to the borrower a reasonable fee for use of the Resources for such time as the Lender makes use thereof. The lender and the borrower agree to negotiate such fee in good faith and in a commercially reasonable manner."

END OF DOCUMENT

APPENDIX 5

SAMPLE FORM GENERAL SECURITY AGREEMENT

(SECTION 14.8)

GENERAL SECURITY AGREEMENT

IN FAVOUR OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

1. **Grant of Security Interest.** _____ (the "**Seller**"), having its chief executive office at _____, as continuing security for the repayment and the performance of each of the Obligations (as defined in Section 5 herein) of the Seller to British Columbia Hydro and Power Authority ("**BC Hydro**") having its head office at 333 Dunsmuir Street, Vancouver, British Columbia, V6B 5R3, grants to BC Hydro, subject only to paragraph 3.1, a continuing, specific and fixed assignment, transfer and mortgage of, charge on and security interest in, all the real and personal property and fixtures of the Seller used or acquired in connection with the ownership, development, construction, operation and maintenance of the Seller's plant described in Schedule A hereto (the "**Seller's Plant**") or otherwise pertaining in any way to, the real property situate at _____, _____legally described as:

Parcel Identifier: _____
Lot _____

Plan _____

(the "**Property**")

including without limitation:

(a) all goods, intangibles, rights, property, assets, equipment materials and contracts required to construct, operate and maintain the Seller's Plant and to interconnect the Seller's Plant to the transmission and distribution system that interconnects, or affects the interconnection or is affected by the interconnection, with the electrical distribution system operated by BC Hydro,

with the Sellers Plant, whether real or personal and whether tangible or intangible, including equipment and other warranties, permits, certificates, licences, and other approvals required for the design, construction, ownership, operation and maintenance of the Seller's Plant, including all the material permits, supply and other contracts, the goodwill in and right to use the name by which the Seller's Plant is commonly known, the books, records and accounts with respect to the Seller's Plant, and all land tenure and land tenure agreements with respect to the Seller's Plant (all of the property referred to in this paragraph collectively with the Seller's Plant, the "**Project Assets**"); and

(b) all proceeds and personal property in any form derived directly or indirectly from any dealing with the Collateral (as defined herein) or any part thereof and all proceeds of proceeds and any part thereof (the "**Proceeds**").

(all of which personal property is referred to herein collectively as the "**Collateral**").

2. **Floating Charge.** As continuing security for the repayment and performance of each of the Obligations, the Seller grants a floating charge to BC Hydro on all present and future real and personal property and interests therein of the Seller, including without limitation, all fixtures, crops, permits, licences, easements, rights-of way, privileges, and improvements, both present and future, used or acquired by the Seller in connection with the ownership, development, construction, operation and maintenance of the Project Assets on the Property, other than such as are validly and effectively charged under paragraph 1 or excluded under paragraph 3. The floating charge created by this Security Agreement shall become a fixed charge when BC Hydro proceeds to enforce payment of the Obligations.

3. **Exclusions**

The security interests, mortgages and charges hereby created shall **NOT EXTEND TO ANY CONSUMER GOODS**. The last day of any term reserved by any lease now held or hereafter acquired by the Seller is hereby excepted out of the security interests, mortgages and charges created hereby. The Seller shall assign and dispose of the same in such manner as BC Hydro may from time to time direct in writing.

4. **Defined Terms.** Unless the context otherwise requires or unless otherwise specified, all the terms used herein without initial capitals which are defined in the Personal Property Security Act, 1989 (British Columbia) or the regulations thereunder, as they may be amended, restated or replaced by successor legislation of comparable effect (collectively, the "**PPSA**"), have the same meaning herein as in the PPSA.

5. **Obligations Secured.** The Collateral constitutes and will constitute continuing security for

the Seller's continuing performance of all its obligations under, and any amounts that may be owed by the Seller to BC Hydro pursuant to, the EPA including any damages for failure to perform its obligations under the EPA (collectively, the "**Obligations**").

6. **Change of Place of Business and Names.** The Seller agrees not to change its places of business or change its name or any name under which it carries on business without giving to BC Hydro 20 day's prior written notice of the change.

7. **Disclosure.** The Seller agrees to deliver to BC Hydro upon request such information concerning the Collateral as BC Hydro may reasonably request.

8. **Proceeds in Trust.** The Seller will and shall be deemed to hold all proceeds in trust, separate and apart from other money, instruments or property, for the benefit of BC Hydro until all amounts owing by the Seller to BC Hydro have been paid in full.

9. **Collection of Accounts.** BC Hydro may, after default under this Security Agreement, notify and direct any party ("**Account Seller**") obligated to pay under any account, chattel paper or instrument constituting Collateral to make all payments whatever to BC Hydro. BC Hydro may hold all amounts acquired from any Account Sellers and any proceeds as part of the Collateral. Any payments received by the Seller whether before or after notification to Account Sellers, shall be held by the Seller in trust for BC Hydro in the same medium in which received, shall not be commingled with any assets of the Seller and shall be turned over to BC Hydro not later than the next business day following the day of their receipt.

10. **Default.** The Seller shall be in default under this Security Agreement upon the occurrence of any of the following events ("**Events of Default**"): The Seller defaults in the payment or performance of any of the Obligations and fails to cure such default within the time allowed under the EPA; the dissolution or termination of existence of the Seller; the insolvency, bankruptcy or business failure of the Seller, or upon the appointment of a receiver, receiver-manager or receiver and manager of any part of the property of the Seller, or the commencement by or against the Seller of any proceeding under any bankruptcy, arrangement, reorganization, dissolution, liquidation, insolvency or similar law for the relief of or otherwise affecting creditors of the Seller, or upon the issue of any writ of execution, warrant, attachment, sequestration, levy, third party demand or garnishment or similar process against the Seller or any part of the Collateral; the institution by or against the Seller of any formal or informal proceeding for the dissolution or liquidation of, settlement of claims against or winding up of affairs of the Seller.

11. **BC Hydro's Remedies on Default.** Upon the occurrence of an Event of Default all of the

Obligations shall become immediately due and payable without notice to the Seller, and BC Hydro may, at its option, proceed to enforce payment of same and to exercise any or all of the rights and remedies contained herein, including, without limitation, the signification and collection of any debts, accounts, claims or monies owed to the Seller or otherwise afforded by law, in equity or otherwise. BC Hydro shall have the right to enforce one or more remedies successively or concurrently in accordance with applicable law and BC Hydro expressly retains all rights and remedies not inconsistent with the provisions herein including all the rights it may have under the PPSA, and, without restricting the generality of the foregoing, BC Hydro may upon such Event of Default:

(a) appoint by instrument in writing a receiver, receiver-manager or receiver and manager (herein a "**Receiver**") of the Seller and of all or any part of the Collateral and remove or replace such Receiver from time to time or may institute proceedings in any court of competent jurisdiction for the appointment of a Receiver. Any Receiver appointed by BC Hydro so far as concerns responsibility for its acts shall be deemed the agent of the Seller and not of BC Hydro. Where BC Hydro is referred to in this Article the reference includes, where the context permits, any Receiver so appointed and the officers, employees, servants or agents of such Receiver;

(b) immediately and without notice enter the Seller's premises and repossess, disable or remove the Collateral and the Seller hereby grants to BC Hydro a licence to occupy any premises of the Seller for the purpose of storage of the Collateral;

(c) retain and administer the Collateral in BC Hydro's sole and unfettered discretion;

(d) dispose of any Collateral by public auction, private tender or private contract with or without notice, advertising or any other formality, all of which are hereby waived by the Seller. BC Hydro may, at its discretion establish the terms of such disposition, including, without limitation, terms and conditions as to credit, upset, reserve bid or price. BC Hydro may also lease the Collateral on such terms as it deems appropriate. The payments for Collateral, whether on a disposition or lease, may be deferred. All payments made pursuant to such dispositions shall be credited against the Obligations only as they are actually received. BC Hydro may buy in, rescind or vary any contract for the disposition of any Collateral and may dispose of any Collateral again without being answerable for any loss occasioned thereby. Any such disposition may take place whether or not BC Hydro has taken possession of the Collateral;

(e) foreclose upon the Collateral in satisfaction of the Obligations. BC Hydro may designate any part of the Obligations to be satisfied by the foreclosure of particular Collateral which BC Hydro considers to have a net realizable value approximating the amount of the designated part of the Obligations, in which case only the designated

part of the Obligations shall be deemed to be satisfied by the foreclosure of the particular Collateral;

(f) carry on or concur in the carrying on of all or any part of the business of the Seller and may, in any event, to the exclusion of all others, including the Seller, enter upon, occupy and use all premises of or occupied or used by the Seller and use any of the personal property (which shall include fixtures) of the Seller for such time and such purposes as BC Hydro sees fit. BC Hydro shall not be liable to the Seller for any neglect in so doing or in respect of any rent, costs, charges, depreciation or damages in connection therewith;

(g) pay any lien, charge or encumbrance that may exist against the Collateral. In any such case the amounts so paid together with costs, charges and expenses reasonably incurred in connection therewith shall be added to the Obligations secured by this Security Agreement;

(h) if the proceeds of realization are insufficient to pay all monetary Obligations, the Seller shall forthwith pay or cause to be paid to BC Hydro any deficiency and BC Hydro may sue the Seller to collect the amount of such deficiency;

(i) subject to applicable law seize, collect, realize, borrow money on the security of, release to third parties, sell (by way of public or private sale), lease or otherwise deal with the Collateral in such manner, upon such terms and conditions, at such time or times and place or places and for such consideration as may seem to BC Hydro advisable and without notice to the Seller;

(j) BC Hydro may charge on its own behalf and pay to others sums for expenses incurred and for reasonable services rendered (expressly including legal services, consulting, receivers and accounting fees) in or in connection with seizing, collecting, realizing, borrowing on the security of, selling or obtaining payment of the Collateral and may add such sums to the Obligations secured by this Security Agreement; and

(k) enter upon the Seller's Plant and take over the construction and/or operation of the Seller's Plant, and take over direction of the Seller's Plant, its employees, management, and Collateral (collectively, the "Resources") as are intended or proposed to be used in the construction and/or operation of the Seller's Plant. BC HYDRO may take possession and have use of the Seller's Plant and all Resources for construction and/or operation of the Seller's Plant, and may construct and/or operate

the Seller's Plant itself, or, at its option, may cause the construction and/or operation of the Seller's Plant to be provided by any other persons or firm whom it may choose to employ, using in so doing, at its option, such of the said Resources as it or such person or firm shall think fit, and it and any such person or firm shall at their option be entitled to remain in the Seller's Plant with employees and others, and to take over direction (and, if necessary, payment) of such of the Seller's employees as may be necessary to construct and/or operate the Seller's Plant, but such employees shall at all times remain employees of the Seller. BC HYDRO agrees to pay to the Seller a reasonable fee for use of the Resources for such time as BC HYDRO makes use thereof. BC HYDRO and the Seller agree to negotiate such fee in good faith and in a commercially reasonable manner

12. **BC Hydro Not Liable for Failure to Exercise Remedies.** BC Hydro shall not be liable or accountable for any failure to exercise any of its remedies.

13. **Allocation of Proceeds.** All monies collected or received by BC Hydro in respect of the Collateral may be held by BC Hydro and may be applied on account of such parts of the Obligations at the sole discretion of BC Hydro.

14. **Extension of Time.** BC Hydro may grant extensions of time and other indulgences, take and give up securities, accept compositions, grant releases and discharges, release the Collateral to third parties and otherwise deal with the Seller's guarantors or sureties and others and with the Collateral and other securities as BC Hydro may see fit without prejudice to the Obligations, or BC Hydro's rights, remedies and powers under this Security Agreement. No extension of time, forbearance, indulgence or other accommodation now, heretofore or hereafter given by BC Hydro to the Seller shall operate as a waiver, alteration or amendment of the rights of BC Hydro or otherwise preclude BC Hydro from enforcing such rights.

15. **Effect of Appointment of Receiver.** As soon as BC Hydro takes possession of any Collateral or appoints a Receiver, all powers, functions, rights and privileges of the directors and officers of the Seller with respect to that Collateral shall cease, unless specifically continued by the written consent of BC Hydro or the Receiver.

16. **Limitation of Liability.** BC Hydro shall not be liable by reason of any entry into or taking possession of any of the Collateral hereby charged or intended so to be or any part thereof, to account as mortgagee in possession or for anything except actual receipts or be liable for any loss on realization or any act or omission for which a secured party in possession might be liable.

17. **Release by Seller.** The Seller hereby releases and discharges BC Hydro and the Receiver from every claim of every nature which may arise or be caused to the Seller or any person claiming through or under the Seller by reason or as a result of anything done by BC Hydro or any successor or assign claiming through or under BC Hydro or the Receiver under the provisions of this Security Agreement unless such claim is the result of gross negligence or wilful misconduct.

18. **Costs.** The Seller will reimburse BC Hydro on demand for all interest, commissions, costs of realization and other costs and expenses (including the full amount of all legal fees and expenses paid by BC Hydro) incurred by BC Hydro or any Receiver in connection with the enforcement of this Security Agreement, the realization, disposition of, retention, protection, insuring or collection of any Collateral, the enforcement of the rights, remedies and powers of BC Hydro or any Receiver, and any costs incurred in complying with control orders and clean-up orders or liabilities to third parties arising out of Seller's activities or while enforcing BC Hydro's security. All amounts for which the Seller is required hereunder to reimburse BC Hydro or any Receiver shall, from the date of disbursement until the date BC Hydro or the Receiver receives reimbursement, bear interest at the highest rate per annum charged by BC Hydro on any of the Obligations.

19. **Security in Addition and not in Substitution, Remedies Cumulative.** The rights, remedies and powers conferred by this Security Agreement are in addition to, and not in substitution for, any other rights, remedies or powers BC Hydro may have under this Security Agreement, at law, in equity or by or under the PPSA or any other statute.

20. **Statutory Waivers.** To the fullest extent permitted by law, the Seller waives all of the rights, benefits and protection given by the provisions of any existing or future statute which imposes limitations upon the rights, remedies or powers of a BC Hydro or upon the methods of realization of security, including any seize or sue or anti-deficiency statute or any similar provisions of any other statute.

21. **Further Assurances.** The Seller shall at all times, do, execute, acknowledge and deliver or cause to be done, executed, acknowledged or delivered all such further acts, deeds, transfers, assignments, security agreements and assurances as BC Hydro may reasonably require in order to give effect to the provisions hereof and for the better granting, transferring, assigning, charging, setting over, assuring, confirming or perfecting the security interests hereby created and the priority accorded to them by law or under this Security Agreement.

22. **Acknowledgement and Waiver.** The Seller hereby acknowledges receiving a copy of this Security Agreement. The Seller waives all rights to receive from BC Hydro a copy of any financing statement, financing change statement or verification statement filed at any time in respect of this Security Agreement.

23. **Entire Agreement.** This Security Agreement and the agreements referred to herein and in the EPA (including without limitation the EPA) constitute the entire agreement between the Seller and BC Hydro and supersede any prior agreements, undertakings, declarations, representations and understandings, both written and verbal, in respect of the subject matter hereof. Any amendment of this Security Agreement shall not be binding unless in writing and signed by BC Hydro and the Seller.

24. **Severability.** Any provision of this Security Agreement prohibited by law or otherwise ineffective shall be ineffective only to the extent of such prohibition or ineffectiveness and shall be severable without invalidating or otherwise affecting the remaining provisions hereof.

25. **Joint and Several Liability.** If more than one person executes this Security Agreement as Seller, their obligations hereunder shall be joint and several.

26. **Included Words.** Wherever the singular or the masculine are used herein, the same shall be deemed to include the plural or the feminine or the body politic or corporate where the context or the parties so require.

27. **Time is of the Essence.** Time shall in all aspects be of the essence in this Security Agreement and no exception or variation of this Security Agreement or any Obligation hereunder shall operate as a waiver of this provision.

28. **Governing Law and Attornment.** This Security Agreement shall be construed and enforceable under and in accordance with the laws of British Columbia. The Seller hereby irrevocably submits and attorns to the jurisdiction of the British Columbia Supreme Court sitting at Vancouver, British Columbia.

29. **Binding Effect.** This Security Agreement shall be binding on the Seller, and its successors, heirs, administrators and executors and enure to the benefit of BC Hydro and the successors and assigns of BC Hydro.

30. EXECUTION(S):

Officer Signature(s)	Execution Date Y	M	D	Seller(s) Signature(s)
_____				_____

OFFICER CERTIFICATION:

Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the **Evidence Act**, R.S.B.C. 1979, c.116, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the **Land Title Act** as they pertain to the execution of this instrument.

SCHEDULE A

SELLER'S PLANT DESCRIPTION

ELECTRICITY PURCHASE AGREEMENT
AMENDING AGREEMENT

PINE CREEK PROJECT

THIS AMENDING AGREEMENT made as of 11 March, 2008,

BETWEEN:

TAKU LAND CORPORATION, a British Columbia company with its office at P.O. Box 408, Atlin, British Columbia, V0W 1A0.

("**Seller**")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, with its Head Office at 333 Dunsmuir Street, Vancouver, B.C. V6B 5R3.

("**BC HYDRO**")

WITNESSES THAT WHEREAS:

A. The Seller and BC HYDRO entered into an Electricity Purchase Agreement made as of November 21, 2006 (the "**EPA Date**") relating to the sale and purchase of electrical energy generated by the Seller's Plant (the "**Electricity Purchase Agreement**"); and

B. The Seller and BC HYDRO have agreed to amend the Electricity Purchase Agreement as hereinafter provided.

NOW THEREFORE in consideration of the premises and other good and valuable consideration, the receipt and sufficient of which the parties acknowledge, the parties hereby covenant and agree as follows:

1. **Definitions**

Capitalized words and expressions used in this Amending Agreement that are defined in the Electricity Purchase Agreement and are not otherwise defined herein, have the meaning given to those words and expressions in the Electricity Purchase Agreement.

2. **Amendments**

The Seller and BC HYDRO agree that with effect as of and from the EPA Date, the Electricity Purchase Agreement is amended as follows:

(a) The Target COD date as specified in item 5 of Appendix 3 to the Electricity Purchase Agreement is amended to read as follows:

Target COD – I January 2009

(b) The Initial Period Expiry Date as specified in item 6 of Appendix 3 to the Electricity Purchase Agreement is amended to read as follows:

Initial Period Expiry Date – 30 June 2008

3. **Electricity Purchase Agreement Confirmed**

The Electricity Purchase Agreement is supplemented and amended only to the extent provided in this Amending Agreement and all provisions of the Electricity Purchase Agreement as supplemented and amended by this Amending Agreement are otherwise confirmed and remain in full force and effect.

4. **Enurement**

This Amending Agreement enures to the benefit of, and is binding upon, the Seller and BC HYDRO and their respective successors and assigns, subject to any terms and conditions respecting assignment contained in the Electricity Purchase Agreement, which provisions apply equally to this Amending Agreement.

IN WITNESS WHEREOF the Seller and BC HYDRO have executed this Amending Agreement by their respective authorized signatory on the dates set forth below.

TAKU LAND CORPORATION

By: _____
Authorized Signatory
Title: CEO
Date: 11 Mar 2008

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

By: _____
Authorized Signatory
Title: Manager, NIA
Date: 2008-03-11

ISSUE: **YIS upgrades**

REFERENCE: **Application, page 3, PDF page 6**

QUOTE: "The Project will also include upgrades to the YIS to accommodate the Project's capacity and energy deliveries (primarily involving AEY System transmission upgrades)."

QUESTION:

a) Please list all expected YIS upgrades and provide a cost estimate for each upgrade, including the amount of added capacity.

b) Please describe where the interconnection metering point will be.

c) Please describe how far down the Tagish Road the AEY line is. Is it a three-phase line? What voltage is that line?

ANSWER:

(a)

Appendix 1 to this response provides AEY's planning level cost estimate for upgrades to the AEY system. These upgrades constitute most of the required YIS system upgrades. Total estimated AEY costs, including for study work to date, are $16.82 million.

Hatch estimates of YEC system upgrade costs total $1.25 million. These include the following allocations: $0.090 million at S150 (new revenue metering and related work), $0.594 at Jakes Corner substation (new revenue metering and related work, new SCADA panel), $0.170 million at Atlin Generating Station (new SCADA panel), $0.190 common costs for all locations (studies, project management, etc.), and 20% contingency ($0.209 million).

The YIS upgrades and related costs remain subject to review at this time. These system upgrade costs are all funded by the Seller, so there will be no impact to Yukon ratepayers.

(b)

The interconnection metering point (i.e., the YEC revenue meter) will be located at the POI located at Seller's Interconnection Substation at Jakes Corner.

(c)

Electrical service on the Tagish Road is provided by AEY via Carcross. Service from Carcross to Tagish is via a 34.5 kV line and from Tagish to Secret Valley Road is served by a single-phase 14.4 kV line that terminates approximately 11 kilometers from Jakes Corner.

Appendix 1: AEY System Upgrades

AEY has provided a planning level cost estimate of $16.8 million with GST (see the table below) for a maximum of 10.575 MW exported at Jakes Corner. The estimated costs include work to upgrade existing line regulator, add two new line regulators, build connection to the new substation at Jakes Corner, provide power quality metering at the PCC, provide protection upgrades, upgrade 40 km of line with 27.2 km of greenfield construction, 13.2 km of build in place construction, DTT from all upstream AEY protection devices to new THELP substation at Jakes Corner, radio communication line with radios at S150, Grey Mountain tower, Jubilee Mountain tower, Carcross closer recloser, Judas Creek reclosers and Jakes Corner substation,

Item		Cost
Prior work	$	217,000
Construction Services	$	80,162
Forestry & Access	$	540,715
Materials	$	3,300,273
Camp	$	2,940,000
Distribution Line Construction	$	3,541,075
Telecom Labour	$	835,344
Telecom Materials	$	862,966
Survey	$	101,587
Health & Safety	$	52,500
Land Admin	$	40,000
Land Planning and Environmental	$	43,810
Engineering	$	113,181
Contingency	$	1,826,903
Management Reserve	$	713,926
Burdens	$	810,494
Total	$	16,019,936
GST	$	800,997
Total w GST	$	16,820,933
Previous payments	$	245,000
Intermediate payment	$	55,000
Remaining	$	16,520,933

ISSUE: **Moon Lake**

REFERENCE: **Application, page 3, PDF page 6, footnote 4**

QUOTE: "In future the Interconnection Substation could potentially be connected directly to a new 69 kV YIS facility if new transmission through Carcross to a Moon Lake pumped storage hydro facility is developed as proposed in the Yukon Energy 10-Year Renewable Electricity Plan. See Figure 2-2."

QUESTION:

a) Please describe the anticipated cost implications of YEC's relationship with AEY if the Moon Lake project proceeds.

ANSWER:

(a)

In the context of the current EPA review, YEC is not aware of any anticipated cost implications of YEC's relationship with AEY if the Moon Lake project proceeds.

The quote references the potential connection of the Jakes Corner Interconnection Substation to a new 69 kV YIS facility if new transmission through Carcross to a Moon Lake pumped storage hydro facility is developed. If this connection was to occur in the future, YEC would need to make arrangements with THELP to enable the connection to occur at THELP's Interconnection Substation – including required provision of the new POI and revenue meter location.

ISSUE: **Thermal displacement**

REFERENCE: **Application, page 5, PDF page 8**

QUOTE: "As reviewed in Section 3 below, the EPA focuses on energy delivery for the Winter Period (defined as January-May and September-December inclusive). Expected Winter Period deliveries to YEC per calendar year are 30.8 GWh LTA energy and 25.2 GWh firm energy during the lowest water year. Figure 2-3 below shows LTA Winter Project deliveries by month at Jakes Corner, and the resulting LTA YIS thermal displacement benefits of 19.6 GWh/year at forecast 2024 YIS load after considering other existing or expected renewable sources."

QUESTION:

a) If 30.8 GWh is provided year-round and the thermal displacement is 19.6 GWh, what is the cost of the remaining 11.2 GWh?

ANSWER:

(a)

The energy cost is the same for the entire commitment of 30.8 GWh. The unit price is calculated to reflect that not all of this energy will displace thermal. This is clear from the calculations in column A of Table A3-1 of the Submission and further explained in response to YUB-YEC-1-24.

YEC cost savings from EPA or other IPP deliveries relate to the resulting thermal displacement. No YEC cost savings are derived from EPA or other IPP deliveries that do not displace thermal generation.

The referenced long-term average (LTA) 30.8 GWh is for EPA deliveries provided only during the defined Winter Period. It reflects the average deliveries over 35 Atlin water years. The LTA thermal displacement estimated to result from these EPA deliveries reflects the average of 38 YIS water years. Figure 2-4 in YEC's Submission highlights the

wide variance over the 38 YIS water years in forecast thermal displacement using 2024 YIS load forecasts.

The estimated LTA thermal displacement was used to develop the EPA energy price to be paid for delivered energy. YEC is required under the EPA to take all of the energy deliveries provided during the Winter Period (i.e., the 30.8 GWh of expected LTA winter deliveries). The EPA price paid per kWh for these deliveries was determined based on the estimated resulting LTA thermal displacement:

- Using $0.19/kWh (2024$) as the expected cost saving for displaced thermal, the 19.6 GWh/year of expected thermal displacement from the EPA winter deliveries were therefore estimated to provide YEC cost savings of approximately $3.72 million per year (2024$).

- The resulting EPA energy price payable for these winter deliveries was set to equal the expected thermal displacement cost savings for YEC, i.e., the average price paid for LTA 30.8 GWh of deliveries equals $0.121/kWh or $3.72 million divided by 30.8 GWh.

Table A3-1 of the Submission provides detailed calculations for the average EPA price payable in 2024$ for the 2024 load forecast ($0.121/kWh) and for the 2035 load forecast ($0.093/kWh). Table A3-2 of the Submission provides the determination of firm and non-firm winter energy prices (2024$/kWh delivered) payable per Section 8.2 of the EPA, based on the calculations in Table A3-1.

ISSUE: **Benefit of winter deliveries**

REFERENCE: **Application, Figure 2-3, page 5, PDF page 8**

QUOTE:

QUESTION:

a) For areas of the blue portions of Atlin deliveries that are above the red line in Figure 2-3, does that mean that YEC would take deliveries when there are no LTA benefits? Why or why not?

ANSWER:

(a)

Yes. YEC will take deliveries under the EPA (as well as under other IPP agreements) when there are no LTA benefits.

This will occur because, under the EPA, YEC is required to purchase all Atlin deliveries during the Winter Period. This requirement reflects both the technical inability to dispatch deliveries on anything less than a multiple day order period, and the Seller inability to accept the financial risks related to payments being provided only when YEC achieves thermal displacement.

The EPA pricing in the agreement is reduced to recognize that certain energy deliveries have no thermal offsets. That is, the EPA energy price was set based on the average LTA thermal displacement expected from winter deliveries. As reviewed in more detail in the response to YUB-YEC-1-11, assuming $0.19/kWh saving for thermal displacements, the average EPA energy price for 2024 winter deliveries is only $0.121/kWh rather than $0.19/kWh – reflecting the ratio of expected LTA thermal displacement to total expected LTA energy deliveries.

ISSUE: **Government grant funding**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Yukon Energy's 10-Year Renewable Electricity Plan assumed government grant funding to support the development of renewable sources that would not otherwise be selected as the lowest cost resources. YEC and THELP are accordingly collaborating on securing government grant funding necessary for the Project to proceed.

Project capital costs have been estimated to date at approximately $206 million. Grant funding of approximately $150 million is being sought from the governments of the Yukon Territory, British Columbia and Canada to support the economics of the Project. Such funding would allow Yukon Energy to purchase energy and capacity from the Project at prices comparable with the lowest cost thermal alternatives, and deliver a reasonable return to THELP."

QUESTION:

a) What are the current "lowest cost thermal alternatives", and what is their cost per megawatt hour?

b) What YEC backup resources will be available to maintain N-1 capacity if THELP's delivery of electricity under the EPA did not occur or were undelivered?

c) What is the minimum amount of thermal generation capacity that YEC will require to maintain N-1 capacity after electricity deliveries under the EPA take effect? How long does YEC expect to have to maintain such thermal generation capacity and from what thermal generation sources? This projection should include YEC's load growth projections for the life of the EPA.

ANSWER:

(a)

"Lowest cost thermal alternatives" has been estimated separately for energy and dependable capacity. The EPA pricing for the current thermal alternative when the Atlin project is first expected (2024) to provide deliveries to YEC assumes the following (see YEC Submission, section 4.1.1 of Appendix B):

- **Energy**: blend fuel 2024 thermal energy generation cost of $0.19/kWh ($19/MWh), based on 90% LNG[1] at 2024 cost of $0.18/kWh and 10% diesel[2] at 2024 cost of $0.30/kWh, before any potential future impact of carbon taxes.

- **Dependable Capacity**: cost for greenfield new diesel generation capital and non-fuel O&M at (2024$) $200/kW-yr. This price is within the bottom end of the range for levelized cost of capacity (LCOC) estimates of YEC levelized cost of capacity (i.e., fixed capital and O&M costs, excluding fuel costs) for a 12.5 MW new diesel generation facility of $175 per kW (2019$) if located at Takhini without any property taxes, and $199.8 per kW (2019$) if located in Whitehorse with related property tax costs (see response to Undertaking #7 in BESS proceeding).[3] The 2019 LCOC costs escalated at 2% per year for inflation to 2024 equal $193 and $220.6 per KW respectively.

Dependable capacity for thermal generation is benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report

[1] LNG fuel price forecast for 2021 GRA was $0.18/kWh – this price is the same as forecast for 2024. The forecast as developed in late 2021 assumed LNG average efficiency for 2019-2021 of 2.63 kWh/litre (vs 2.66 for 2021 GRA), forecast LNG cost of $20.44/GJ (vs. $20.89/GJ for 2021 GRA – assumes increase in commodity price to $3.34/GJ is more than offset by decrease in transportation charge) and energy content of 0.02367HHV GJ/l (vs 0.02309 GJ/l for 2021 GRA).

[2] Average diesel fuel price forecast for 2021 GRA was $0.205/kWh, based on prices in mid-2020. The price forecast for 2024 reflects YEC October 2021 diesel fuel prices (average $0.302/kWh).

[3] Estimates as per response to Undertaking #7 in BESS proceeding, based on 2021 GRA WACC of 4.794% and Midgard estimated costs (2019$) for 12.5 MW new diesel plant with five 2.5 MW units and 40 year life ($2.6 million per MW capex, fixed year 1 non-fuel O&M of $64,500/MW without property taxes and $91,000/MW with Whitehorse property taxes).

was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[4]

(b)

YEC's dependable capacity requirement provides backup for the largest single contingency event (N-1) disruption of generation supply. This currently results in approximately 37 MW of backup based on possible disruption of the Aishihik Generating Station supply. To require additional capacity to back up the EPA resource, or in fact any other resource would effectively require double-redundancy or N-2 contingency planning. However, there are certain risk mitigation protections in the EPA.

Section 4.3 of YEC's Submission reviews risks related to dependable capacity service reliability.

Construction and Commissioning - Section 4.3 of the EPA provides that YEC may proceed to rent diesel generating units for this Peak Winter Period (PWP) if THELP is unable to confirm to YEC on or before June 1, 2024 the availability of Dependable Plant Capacity for the first PWP, and no Dependable Capacity Payment will be payable by YEC to THELP for the first PWP for Dependable Plant Capacity that was already provided by such rented diesels.[5]

Operations - During subsequent operation of the Atlin Project after commissioning the risk that dependable capacity is not provided as planned during a PWP varies materially depending on when the issue is identified as well as its magnitude and duration:

- Available evidence from 35 water years and the SNC Lavalin analysis (see Section 2.1.3 of the YEC Submission) confirms that water availability is not an expected

[4] YUB Report to Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

[5] YEC currently relies on rented diesels during the winter period to address N-1 dependable capacity requirement shortfalls on the YIS. In order to proceed with such rentals, YEC typically needs to know by June what diesel rental requirements exist for the subsequent winter. Absent notification by June of a such a requirement, YEC would not be able to have in place during the subsequent winter the needed dependable capacity to address an N-1 event during an extended cold weather period of two weeks. Section 6.2 of the EPA requires as follows throughout the Term: "If Seller becomes aware that it will not be able to provide 100% of the Dependable Plant Capacity Committed for the following Peak Winter Period due to factors other than water availability to Surprise Lake, Seller will provide, as soon as practicable, Notice to Buyer to permit Buyer when feasible to make alternative arrangements."

risk affecting Project ability to provide dependable capacity as required during the PWP.

- During a PWP it is possible that issues with the ice cover of the power canal or other brief disruptions affecting THELP's Plant may result in short term disruptions to the delivery of dependable capacity. Such disruptions are not expected to occur on any frequent basis, and would be unlikely to affect overall YIS service reliability unless they are concurrent with an N-1 event during a cold weather period.

- To address notification of other constraints on THELP's Plant capability regarding dependable capacity, Section 6.2 of the EPA requires as follows throughout the Term: "If Seller becomes aware that it will not be able to provide 100% of the Dependable Plant Capacity Committed for the following Peak Winter Period due to factors other than water availability to Surprise Lake, Seller will provide, as soon as practicable, Notice to Buyer to permit Buyer when feasible to make alternative arrangements."

    - If such Notice is provided with sufficient time (i.e., by June prior to a PWP) YEC would expect to be able to secure rental diesel capacity as required to ensure reliable service for the coming PWP – and the EPA provisions would ensure that this capacity would be excluded from any dependable capacity payments for that PWP.

    - Otherwise, if YEC is unable to secure rental diesel capacity replacement due to lack of time or other inability to secure rentals, there is a risk resulting that YIS would have a N-1 dependable capacity shortfall for the affected PWP. This same risk relates to all of YEC's facilities and is not expected to be a material risk unless there is in fact an N-1 event during a cold weather period during the affected PWP.

(c)

Yukon Energy's 10-Year Renewable Electricity Plan as summarized in Section 4.1.1 of YEC's Submission, in Figure 4-1 and Table 4-1, provides the best available forecast on thermal generation capacity that YEC will require to maintain N-1 capacity after electricity deliveries under the EPA take effect in late 2024. These projections include YEC's non-industrial peak load growth (as relevant for N-1 determinations) forecast to 2041/42 (in Figure 4-1).

Figure 4-1 and Table 4-1 indicate a forecast YIS N-1 capacity shortfall for winter 2024/25 without the Project of 17.2 MW related to non-industrial YIS load.[6] This capacity shortfall forecasts existing YEC and AEY thermal generation capacity of 36.4 MW plus diesel replacements of 12.5 MW (total permanent thermal capacity of 38.9 MW). The capacity shortfall is assumed to be met with rented diesel capacity unless other new dependable capacity is developed.

- Without the Project and Moon Lake pumped storage, this capacity shortfall increases to 27.6 MW by 2027/28 (requiring 16 of 1.8 MW diesel rental units, plus any spares needed to support these units), and then to 41.5 MW by 2030/31 (requiring 24 rented diesel units).[7] Figure 4-1 indicates this capacity shortfall increases further by about 10 MW by 2041/42, based on non-industrial peak load growth and no changes in permanent resource availability. Non-industrial peak load forecasts have not been extended beyond 2041/42 – however, there is clear potential for ongoing further material growth over the balance of the EPA 40-year term to 2064.

- The EPA is expected to reduce this capacity shortfall and diesel rental requirement by 8.0 MW. Rented diesel requirements would be forecast to be reduced accordingly (ignoring any additional requirement for spares):
    - In winter 2024/25, from 16 units to 11 units (reduction of 5 units)
    - In winter 2030/31, from 24 units to 19 units (reduction of 5 units)

- Moon Lake Pumped Storage Project development is projected to provide an additional 35 MW in Phase 1 and a further 10 MW in Phase 2. The 10-Year Renewable Electricity Plan proposed Phase 1 completion in 2028 (resulting in a 10.8 MW capacity surplus in winter 2028/29) and Phase 2 completion in 2031 (when the capacity shortfall would otherwise re-emerge in winter 2031/32). Figure 4-1 indicates that with these resource developments a capacity shortfall would be likely once again to re-emerge after winter 2041/42. The Moon Lake Pumped Storage Project remains today at a very early planning stage, and would require a major level of federal funding support in order to proceed after necessary planning

[6] The forecast is after forecast DSM, the WH2 uprate, diesel replacements and BESS.
[7] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied in forecast years so long as the single contingency, N-1, criterion was met.

has occurred. The feasibility of this project is expected to be further clarified by the time that EPA deliveries commence.

ISSUE: **Low water sequence**

REFERENCE: **Application, Figure 2-4, page 6, PDF page 9**

QUOTE:

QUESTION:

a) For the assumption for "Average for Low Water Sequence", which is the solid red line in Figure 2-4, explain how likely it is that Atlin can provide contracted electricity deliveries at full levels to YEC if there are low water or drought conditions.

b) Would low water or drought conditions impact Atlin's operations?

ANSWER:

(a)

The LTA winter deliveries from Atlin with the EPA reflect full delivery during winter months each year based on available water year information for the Atlin project (35 years) as provided in Table A1 of YEC's Submission.

Figure 2-4 assumes LTA Atlin deliveries throughout the model range of YIS water years. No model development has been feasible to date to assess potential correlation of a YIS low water sequence with low water conditions at Atlin, and therefore no probability assessment of that possible correlation can be provided at this time.

The EPA energy pricing separates a price for "firm" energy deliveries (the first 25.2 GWh during the Winter Period in a calendar year, based on the lowest recorded Atlin water year) from the price for "non-firm" energy deliveries (all energy delivered above 25.2 GWh during the Winter Period in a calendar year). Row 5 of Table A3-1 in YEC's Submission shows that most of the LTA thermal displacement benefits are secured with the firm energy deliveries:

- 2024 load forecast: firm accounts for 89% of all LTA thermal displacement benefits.
- 2035 load forecast: firm accounts for 95% of all LTA thermal displacement benefits.

Available analysis in Table A1 of Atlin EPA deliveries over the 35 Atlin water years indicates the following for Atlin water years with deliveries less than 90% of the 30.8 GWh/year LTA (i.e., below 27.7 GWh) used in Figure 2-4:

- 2 years below 26 GWh (1978 at 25.2 GWh and 1979 at 25.8 GWh).
- 3 years above 26 GWh, and below 27 GWh (1965 at 26.55 GWh, 1966 at 26.8 GWh and 1985 at 26.9 GWh).
- 1 year above 27 GWh, and below 27.7 GWh (1973 at 27.4 GWh).

(b)

Low water conditions at Atlin are not expected to lower the dependable capacity of 8.0 MW provided by the EPA. As reviewed in Section 2.2 of the EPA Submission, expected energy deliveries during each Peak Winter Period (PWP), based on the Project's Surprise Lake storage and its 35 water years of record,[1] are expected to enable a full 8.0 MW of capacity to be delivered to YEC each year at Jakes Corner for at least 94% of the PWP days, i.e., for 70.5 of the 75 or 76 days in the PWP. This is more than enough days to cover the 20 or less days of the PWP period when minus 30ºC or lower temperature has been recorded at Whitehorse.[2]

[1] See Table A2 of the Submission.

[2] YEC's winter peak non-industrial load forecast assumes -38ºC, with approximately 8 MW load added by an average daily temperature drop below -30ºC. The forecast LTA deliveries from the Project during a PWP as stated apply regardless as to whether the Surprise Lake reservoir is full in the prior October provided that the load for the Existing Plant to supply the BC Hydro Atlin community load is 6.93 GW.h/yr or less as per the load forecast for 2032. See Section 1.1 of Appendix B of this Submission for more details and sensitivity assessments.

ISSUE: **Project capital costs**

REFERENCE: **Application, page 6, PDF page 9**

PREAMBLE: Project capital costs have been estimated to date at approximately $206 million.

QUESTION:

a) On a best estimate basis, provide the capital cost breakdown for this project between generation (production) costs and transmission costs.

ANSWER:

(a)

The Project is being developed by THELP, and YEC is therefore only aware of capital cost estimates and breakdowns as provided by THELP. Section 2.1(d)(iii) of the EPA requires, as a Condition Precedent to be satisfied, by May 31, 2022, that THELP will have submitted to YEC a detailed funding plan that includes independent third party estimates of capital costs as well as sources of grant funding from governments and debt financing third party lenders.

The $206 million estimate (2024$) for Project capital costs reflects information provided to YEC by THELP in spring 2021, with adjustment to reflect late 2021 estimates for YEC/AEY System Upgrade Costs. This estimate included the following (the generation and transmission/substation components include estimates for construction/ procurement, owner's costs, contingencies, escalation and financing costs):

Generation Plant	$136.2 million
Transmission/ Substation Plant	$53.3 million
YEC/AEY System Upgrades	$16.5 million
Total Project Capital Cost	$206 million

YEC understands that the above estimate is being revised by THELP based on review with its owner's engineer and selected contractors.

ISSUE: **Grant funding**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Grant funding of approximately $150 million is being sought from the governments of the Yukon Territory, British Columbia and Canada to support the economics of the Project."

QUESTION:

a) What parts of the project would B.C. government funding cover?

b) What parts of the project would Yukon government funding apply to?

c) What parts of the project would federal government funding apply to?

d) Please describe each of the grants, the amounts of each of the grants, and the current status and completion dates of each of the grant applications.

e) Please explain the funding source for the $56 million in costs for the project not covered by government grants.

ANSWER:

(a), (b), (c) and (d)

The Project is being developed by THELP, and YEC is therefore only aware of THELP's funding source information as provided by THELP or as provided in joint discussions with government grant funders. We are not currently aware of any grant funding being allocated only to specific parts of the project rather than to the overall project. The Yukon government has committed $50 million to the Atlin Hydro Expansion Project. Grant funding to be provided by other governments continues to be under discussion, and details cannot be appropriately provided at this time.

Section 2.1(d)(iii) of the EPA requires, as a Condition Precedent to be satisfied by May 31, 2022, that THELP will have submitted to YEC a detailed funding plan that includes

independent third party estimates of capital costs as well as sources of grant funding from each government and debt financing third party lenders.

(e)

YEC understands that THELP is in discussion with the Canadian Infrastructure Bank (CIB) for debt financing related to the Project. YEC does not have further information at this time on other funding sources beyond government grants and CIB.

ISSUE: **Lowest cost thermal alternative**

REFERENCE: **Application, page 6, PDF page 9**

QUOTE: "Such funding would allow Yukon Energy to purchase energy and capacity from the Project at prices comparable with the lowest cost thermal alternatives, and deliver a reasonable return to THELP."

QUESTION:

a) Describe the lowest cost thermal alternatives.

b) What is the cost of the lowest cost thermal alternative?

c) After regular deliveries from the EPA begin, how many rented diesel generators will YEC need to ensure N-1 capacity is maintained going forward?

d) Will the number of such generators increase as the YIS load increases, and if so, by how many?

ANSWER:

(a) and (b)

Please see response to YUB-YEC-1-13(a).

(c) and (d)

Please see the response to YUB-YEC-1-13(c). Until such time as Moon Lake Pumped Storage is in service, the number of rental units required on the YIS is forecast to increase as peak non-industrial load increases, and the Atlin EPA is expected to reduce this number by five units in each year (see response to YUB-YEC-1-13(c)). The Moon Lake Pumped Storage Project is planned in two phases to remove the need for rented diesels for 10+ years.

ISSUE: **YIS system upgrades**

REFERENCE: **Application, page 7, PDF page 10**

QUOTE: "THELP is responsible for all AEY and YEC system upgrade costs needed to connect the Project to the YIS. Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY."

QUESTION:

a) Does the referenced quote mean all connection costs up to and at Jakes Corner, including substation and metering costs?

b) Does this include upgrades to the AEY transmission system? If so, please describe those upgrades.

c) What are the estimates for each of these connection costs?

ANSWER:

(a) (b) and (c)

THELP is responsible for the cost of design, construction and maintenance of transmission and substation assets at Atlin, from Atlin to Jakes Corner, and at the Interconnection Substation at Jakes Corner. The referenced quote addresses THELP's additional responsibility for all AEY and YEC system upgrade costs needed on the existing YIS for the Project's connection to the YIS, including responsibility for the cost of any additional metering requirement.

AEY and YEC system upgrades as referenced in the quote are upgrades to the existing AEY (Jakes Corner to Whitehorse, including extending existing transmission to the new Interconnection Substation) and YEC (Whitehorse substation S150) transmission systems that are part of the YIS. YEC system upgrades also include facilities required at the

Interconnection Substation (i.e., YEC revenue meter). Please see response to YUB-YEC-1-9(a) for information on these System Upgrades and related estimated costs.

ISSUE: **Starting templates**

REFERENCE: **Application, page 8, PDF page 11**

QUOTE: "The Parties used as a starting template for the negotiation an amalgam of the YEC Standing Offer Program (SOP) EPA and the BC Hydro Independent Power Producer (IPP) Large Project EPA, and certain other commercial principles and basic terms relevant to the Parties."

QUESTION:

a) Please provide copies of the YEC Standing Offer Program EPA and the BC Hydro Independent Power Producer (IPP) Large Project EPA.

b) Does BC Hydro define a "large project EPA"? If so, please provide that definition.

c) To the extent that YEC is able to answer, what were the commercial principles relevant to the parties?

ANSWER:

(a)

Please see Attachment 1 and Attachment 2 to this response.

(b)

Per Attachment 2 to this response, a large project is defined as a Project having a Plant Capacity of 10 MW or more.

(c)

Section 3.4.1 of the YEC Submission summarizes the key principles relevant to YEC that were reflected in the EPA commercial terms.

ELECTRICITY PURCHASE AGREEMENT

BETWEEN

[SELLER]

- and -

[UTILITY]

[PROJECT NAME]

(YUKON STANDING OFFER PROGRAM)

Dated the ___ day of ____, 20__

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[UTILITY]

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

STANDING OFFER PROGRAM

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of the __ day of ____, 20__

BETWEEN:

[SELLER], a corporation incorporated under the laws of _____ ("**Seller**")

- and -

[UTILITY], a corporation incorporated under the laws of the Yukon ("**Buyer**")

WHEREAS:

A. The Government of Yukon issued the *Energy Strategy for Yukon* in January 2009 and in October 2015 issued the *Independent Power Production Policy* as reviewed and updated in October, 2018 (the "**IPP Policy**") as part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy". The IPP Policy created a framework for the development of the Standing Offer Program. In support of the objectives of the IPP Policy, the Government of Yukon issued the SOP OIC and, together with the Utilities, developed the SOP Rules;

B. Seller has proposed the development of the Project on the Electrical Grid pursuant to the Standing Offer Program and such Project has been reviewed and approved in accordance with the SOP Rules; and

C. This EPA is being entered into by the Parties in respect of the Project under the Standing Offer Program in accordance with the SOP Rules.

NOW THEREFORE Seller and Buyer agree as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION AND SCHEDULES

1.1 Definitions and Interpretation

The definitions and certain principles of interpretation that apply to this EPA are set out in Schedule "A".

1.2 Schedules

The following Schedules attached hereto are incorporated into and made a part of this EPA:

Schedule "A"	-	Definitions and Interpretation
Schedule "B"	-	Project Description

Schedule "C"	-	Form of Annual Operating Plan
Schedule "D"	-	System Interconnection Study Report
Schedule "E"	-	Monthly Energy Shortfall Payment
Schedule "F"	-	Termination Payment
Schedule "G"	-	System Interconnection Guidelines
Schedule "H"	-	Joint Operating Procedure
Schedule "I"	-	Delivery Time Adjustment Table

ARTICLE 2
CONDITIONS PRECEDENT AND TERM

2.1 Conditions Precedent

(a) Except as provided in this Section, this EPA has no legal force until the Conditions Precedent described in Schedule "B" are satisfied by Seller or waived by Buyer. The Conditions Precedent may only be waived by Buyer by notice in writing to Seller.

(b) Seller will:

(i) seek to satisfy each of the Conditions Precedent on or before the Condition Date;

(ii) keep Buyer informed of any circumstances which may result in any of those Conditions Precedent not being satisfied in accordance with their terms; and

(iii) promptly notify Buyer upon satisfaction of any of those Conditions Precedent and provide such supporting evidence as may be reasonably required by Buyer.

(c) If the Conditions Precedent are not satisfied or waived on or before the Condition Date, or it becomes apparent that the Conditions Precedent will not, in the reasonable opinion of Buyer, be satisfied by the Condition Date, the Conditions Precedent will be taken to have failed and Buyer shall be entitled to terminate this EPA, in which event each Party shall release the other from any and all claims, damages, costs, expenses or liabilities whatsoever incurred by it and its Affiliates in relation this EPA provided that (i) Seller shall remain liable for all costs incurred by Buyer in respect of the System Interconnection Study Report, System Upgrade Costs or New Interconnection Facilities Costs and (ii) otherwise each Party shall be responsible for its own costs incurred by it in connection with this EPA.

(d) Section 2.1(a) does not apply to this Article 2, Section 3.5 and Articles 10, 11, 12, 13 and 15 which shall be in full force and effect from the date of this EPA.

2.2 Term

Subject to Section 2.1, this EPA shall commence on the Effective Date and continues for the period specified in Schedule "B", unless it is terminated earlier in accordance with this EPA.

ARTICLE 3
CONSTRUCTION AND OPERATION

3.1 Construction and Operation Costs, Liabilities and Actions

Seller will be fully responsible for the permitting, design, engineering, construction, Interconnection, commissioning, operation, maintenance, reclamation and decommissioning of the Seller's Plant and shall be responsible for all costs, expenses, liabilities and other obligations associated with such activities.

3.2 Standard of Construction and Operation

Except as otherwise consented to in writing by Buyer, such consent not to be unreasonably withheld, conditioned or delayed, Seller will ensure that the location, design, engineering, construction, Interconnection, commissioning, operation and maintenance of the Seller's Plant, are and will be carried out at all times during the Term:

(a) in accordance with the description of the Seller's Plant in Schedule "B" and the information in the Application in all material respects;

(b) in compliance with the Project Standards; and

(c) by qualified and experienced individuals.

The Parties shall conduct their respective operations in accordance with the Joint Operating Procedure.

3.3 Project Changes

Without Buyer's prior written consent, not to be unreasonably withheld, conditioned or delayed Seller will not make any change to:

(a) the Seller's Plant as described in Schedule "B"; or

(b) any other aspects of the Seller's Plant or the information in any System Interconnection Study Report completed for Seller's Plant prior to the Effective Date which would require changes by Buyer to the System Upgrades where such change would increase Buyer's liability for any costs or otherwise increase the obligations or risks of Buyer with respect to the Seller's Plant or any other project.

Seller acknowledges that Buyer may require, as a condition of its consent to any change described in this Section, that Seller agree in writing to reimburse Buyer for any reasonable incremental liability for any losses, costs and damages incurred by Buyer or any third party, with respect to the Seller's Plant or any other project, as a result of any change described in this Section. Buyer may also require that Seller provide performance assurance or security to Buyer in order to ensure that Buyer has no financial exposure in respect of such reimbursement obligation.

3.4 Development Progress Reports

Seller will deliver a Development Progress Report to Buyer on each January 1, April 1, July 1 and October 1 after the Effective Date until Seller's COD. Buyer shall be entitled to request such

additional information as it may reasonably require from time to time in respect of Seller's development of Seller's Plant.

3.5 Responsibility for Upgrade Costs

Seller will be responsible for and shall pay Buyer for all System Upgrade Costs and New Interconnection Facilities Costs in accordance with the following:

(a) the System Interconnection Study Report sets out Buyer's estimate of System Upgrade Costs and the New Interconnection Facilities Costs. Seller shall (i) pay to Buyer in advance an amount equal to such estimate of System Upgrade Costs and New Interconnection Facilities Costs ("**Upgrade Costs Advance**") and/or (ii) provide such other security in form, substance and amount as may be acceptable to Buyer in its Discretion to secure the obligation of Seller to pay such costs ("**Upgrade Costs Security**"). Buyer shall not be required in any circumstances to accept Upgrade Costs Security except in its Discretion. Buyer shall not be required to perform any work or incur any System Upgrade Costs or New Interconnection Facilities Costs where Buyer determines in its Discretion that the amount of Upgrade Costs Advance it has received together with any Upgrade Costs Security is not sufficient to adequately secure the obligation of Seller to pay all System Upgrade Costs and New Interconnection Facilities Costs and Seller shall forthwith provide to Buyer such additional Upgrade Costs Advance and/or Upgrade Costs Security as may be reasonably required by Buyer;

(b) Buyer will exercise Good Industry Practice to perform, or cause to be performed, the work required in respect of the System Upgrades and the New Interconnection Facilities for the Project. Buyer shall be entitled to draw upon the Upgrade Costs Advance and Upgrade Costs Security from time to time in its Discretion to satisfy any System Upgrade Costs and New Interconnection Facilities Costs as and when incurred by Buyer; and

(c) notwithstanding the estimate of System Upgrade Costs and New Interconnection Facilities Costs provided by Buyer to Seller contemplated in Section 3.5(a) or the amount of any Upgrade Costs Advance and Upgrade Costs Security provided by Seller, Seller shall be responsible for and shall pay Buyer the actual System Upgrade Costs relating to the System Upgrades incurred by Buyer. Following the completion of the System Upgrades and the payment in full by Seller of all System Upgrade Costs incurred by Buyer for such work, Buyer shall release to Seller any undrawn portion of the Upgrade Costs Advance and Upgrade Costs Security**.**

3.6 Metering

As part of the System Upgrades and New Interconnection Facilities, Buyer will install and maintain an appropriate Meter installation at the POI, and ensure that such Meter is tested and sealed according to any Measurement Canada standards. Seller will allow Buyer to access the Seller's Plant as may be necessary from time to time to install and maintain the Meter at the POI. If there is any dispute regarding the accuracy of the Meter, either Party may give notice to the other Party of the dispute. In that case, the Parties will resolve the matter in accordance with the *Electricity and Gas Inspection Act* (Canada).

3.7 Insurance

Seller will, at its cost, obtain and maintain (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $5,000,000, and (b) property insurance, with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender may require. All commercial general liability policies must include Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must include a waiver of subrogation in favour of Buyer. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Yukon and must be endorsed to provide to Buyer 30 days' prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. Seller will give Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by Seller under this Section not more than 30 days after the effective date of coverage and promptly upon renewal thereafter. Seller will be responsible for the full amount of all deductibles under all insurance policies required to be maintained by Seller under this Section.

3.8 Seller's COD

(a) Except with Buyer's prior written consent, Seller's COD may not occur earlier than 90 days prior to Target Seller's COD.

(b) Buyer will not be required to incur any incremental expense or other liability of any kind to enable Seller's COD to occur prior to Target Seller's COD.

3.9 Change in Target Seller's COD

If the estimated date for completing the System Upgrades or the New Interconnection Facilities as required to achieve Buyer's COD is later than 90 days prior to the Target Seller's COD, Buyer shall provide notice to Seller of such delay and, provided Seller is not responsible for any delay in completing the System Upgrades or the New Interconnection Facilities (including a failure to pay amounts contemplated in Section 3.5), upon Seller's written request that the Target Seller's COD be postponed, Buyer will postpone the Target Seller's COD to the estimated date for completing the System Upgrades and the New Interconnection Facilities plus 90 days.

3.10 No Liability For Delay

Buyer shall exercise reasonable commercial efforts to achieve Buyer's COD prior to Target Buyer's COD. Buyer will have no liability under this EPA for delays in completion of (a) any System Upgrades or the New Interconnection Facilities, or (b) other work undertaken by Buyer or any of Buyer's Affiliates on the Seller's Plant side of the POI, in each case howsoever arising.

3.11 Outages

(a) **Notice of Seller's Outage** - Seller will notify Buyer of any Outages in Seller's Plant, or changes in any such Outages, by delivering to Buyer an Outage Notice or revised Outage Notice:

(i) promptly in the case of a Forced Outage or a Maintenance Outage;

(ii) not less than 90 days in advance of any Planned Outage, or such shorter time period with Buyer's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(iii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(b) **Notice of Buyer's Outage** - In addition to Buyer's reporting requirements under Section 4.8(d), Buyer will notify Seller of any Planned Outages that will result in a Buyer's Distribution/Transmission Constraint or changes in any such Planned Outages, by delivering to Seller an Outage Notice or revised Outage Notice:

(i) not less than 90 days in advance of any such Planned Outage, or such shorter time period with Seller's written consent, such consent not to be unreasonably withheld, delayed or conditioned; and

(ii) promptly in the case of any changes to the duration, start time or end time of any Outage.

(c) **Coordination and Scheduling of Outages -** Seller will coordinate all Planned Outages or Maintenance Outages with Buyer's maintenance schedule or other requirements where such schedule or requirements are publicly available or otherwise notified to Seller.

3.12 Annual Operating Plan

On or before October 31 in each year during the Term, Seller will provide to Buyer its Annual Operating Plan, including any required update to the then current Annual Operating Plan, for the 12-month period commencing on January 1 of the next year. Seller will promptly provide Buyer with a revised Annual Operating Plan from time to time upon Seller becoming aware of any expected material change in the original Annual Operating Plan for that period. The Parties agree the Annual Operating Plan is provided for planning purposes and does not guarantee or limit the quantity or timing of Delivered Energy to the POI.

ARTICLE 4
PURCHASE AND SALE OBLIGATIONS

4.1 Energy prior to Buyer's COD

Subject to satisfaction of all obligations of Seller under this EPA, upon the occurrence of Seller's COD but prior to the occurrence of Buyer's COD, Buyer will not be obligated to purchase, or accept delivery from Seller of, any Energy, provided if Buyer does accept, in its sole discretion, delivery of Energy at the POI, Buyer will pay for such Energy accepted by Buyer prior to Buyer's COD in accordance with Section 5.1.

4.2 Energy after Buyer's COD

From and after Buyer's COD for the remainder of the Term, Seller will sell and deliver all Energy to Buyer at the POI and Buyer will, subject to Sections 4.3 and 4.4, purchase and accept delivery of all Delivered Energy. Buyer will pay for Delivered Energy from and after Buyer's COD in accordance with Section 5.1.

4.3 Limit on Delivered Energy and Capacity

Notwithstanding the foregoing provisions of this Article 4:

(a) in any hour, Buyer will not be obligated at any time to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Seller's Plant Capacity in such hour (as measured in KWh) and no amount will be payable by Buyer for Delivered Energy in excess of the Seller's Plant Capacity in such hour, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI;

(b) in any calendar year, Buyer will not be obligated to purchase or accept delivery from Seller at the POI of any Energy generated in excess of the Project Energy Volume and no amount will be payable by Buyer for Delivered Energy in any such calendar year in excess of the Project Energy Volume in such calendar year, whether prior to or after COD, and regardless of whether Buyer consented to and accepted delivery of such Energy at the POI; and

(c) in determining the total amount of Delivered Energy for a year, month, hour or any other time period under this EPA for any purpose, the amount of Delivered Energy in each hour of such time period will not exceed the Seller's Plant Capacity in such hour, even if Seller delivered to the POI Energy in excess of such amounts, or the Seller's Plant was capable of generating Energy in excess of such amounts.

4.4 Distribution/Transmission Constraints

Buyer will not be in breach or default of its obligations under Sections 4.1, 4.2 or 5.1 if Buyer is not able to accept delivery of Energy at the POI as a result of a Distribution/Transmission Constraint. Buyer will have no liability with respect to a Distribution/Transmission Constraint, except as set out in Section 4.8, if applicable.

4.5 Exclusivity

(a) Seller will not at any time during the Term commit, sell or deliver any Energy (or related Environmental Attributes) to any Person other than Buyer under this EPA. Seller will not use any Energy (or related Environmental Attributes) for any purpose whatsoever except for sale to Buyer under this EPA. These prohibitions do not apply if, and for so long as, Buyer is in breach of its obligations under Section 4.2.

(b) Seller shall not be entitled to interconnect a generating facility to the Seller's Plant and transmit electricity via the Seller's Plant to the POI.

4.6 Custody, Control, Risk of and Title To Energy

Custody, control, risk of, and title to, all Energy (including any Delivered Energy exceeding the limits set out in Section 4.3 even where Buyer has not paid for such excess Delivered Energy) shall pass from Seller to Buyer at the POI. Seller will ensure that all Energy delivered to Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances.

4.7 Line Losses

Seller will be responsible for all Line Losses, costs and liabilities relating to the transmission of Energy and other electricity, if applicable, from the POI to the interconnection point between the New Interconnection Facilities and the Electrical Grid. Such Line Losses shall be determined in accordance with the Line Loss Methodology.

4.8 Distribution/Transmission Constraint

(a) If, in any month after Buyer's COD, Seller is unable to deliver Energy at the POI or Seller's ability to deliver Energy at the POI is reduced solely as a result of a continuous Distribution/Transmission Constraint which exceeds 30 minutes in duration and which:

(i) is not caused by a Planned Outage by Buyer of the Distribution System or Transmission System;

(ii) is not caused by an event beyond the reasonable control of Buyer; and

(iii) is not caused by Seller, the Seller's Plant or anything on Seller's side of the POI;

(a "**Non-Permitted Distribution/Transmission Constraint**") then, notwithstanding that Buyer is excused under Section 4.4 from its obligations under Section 4.2, Buyer shall pay Seller, for each calendar month in which the Non-Permitted Distribution/Transmission Constraint has occurred, the Monthly Energy Shortfall Payment calculated in accordance with Schedule "E" less any costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint.

(b) Buyer will not be required to pay any Monthly Energy Shortfall Amount under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure; or

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Non-Permitted Distribution/Transmission Constraint occurs.

(c) Seller will maintain accurate and complete Records of all costs Seller avoided or, acting reasonably, could have avoided during the Non-Permitted Distribution/Transmission Constraint and will report all such costs to Buyer and provide Buyer with all information required to calculate such costs.

(d) Buyer will give Seller notice of all Distribution/Transmission Constraints in each month which individually exceed 30 minutes in duration when it provides its monthly statements in accordance with Section 5.3.

(e) In the event of a Dispute by the Parties in respect of the amount of any Monthly Energy Shortfall Amount, the matter shall be resolved in accordance with Article 12.

4.9 Buyer Dispatch/Turn-Down Right

(a) Buyer may at any time during the Term deliver notice to Seller requiring Seller to Dispatch/Turn-Down and Seller will promptly comply with any such direction except to the extent that any operational, technical or regulatory constraint prevents or limits Seller's ability to comply with such direction.

(b) For each hour of the applicable Dispatch/Turn-Down, Buyer will pay Seller an amount equal to:

(i) the price payable for post-COD Delivered Energy under Section 5.1 multiplied by (A) the aggregate of the duration of the applicable Dispatch/Turn-Down (measured as a fraction determined as the aggregate number of minutes in such Dispatch/Turn-Down period divided by 60) multiplied by (B) an amount equal to the positive difference, if any, of (1) the "Non-Permitted Distribution / Transmission Constraint Hourly Deemed Energy" set out in Table E-1 of Schedule "E" for the applicable calendar month less (2) the amount of Delivered Energy in such hour of Dispatch/Turn-Down (the positive difference being the "**Dispatch/Turn-Down Deemed Energy**"); less

(ii) any costs Seller avoided or, acting reasonably, could have avoided during the period of the Dispatch/Turn-Down.

(c) Buyer will not be required to pay any amount in respect of Dispatch/Turn-Down Deemed Energy under this Section in any of the following circumstances:

(i) during any period specified as a Seller's Outage in any Outage Notice, revised Outage Notice or in the Annual Operating Plan or during any other period where the Seller's Plant would otherwise not have been operating;

(ii) during any period when either Party is or would be excused, in accordance with Section 14.1, from its obligation to deliver or to accept delivery of Energy as a result of Force Majeure;

(iii) if Seller has not provided Buyer with an Annual Operating Plan in accordance with Section 3.12 for the year in which the Dispatch/Turn-Down occurs;

(iv) during any other hour when the Seller's Plant would otherwise not have been operating if there had been no Dispatch/Turn-Down notice; or

(v) where Buyer's requirement for Seller to Dispatch/Turn Down is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2.

(d) Where Buyer requires the Dispatch/Turn-Down as result of a Non-Permitted Distribution/Transmission Constraint, Section 4.8 will apply.

4.10 Electric Service to Seller

If at any time Buyer delivers electrical energy to service Seller's Plant Load, then such electrical energy shall be accounted and paid for separately under the applicable agreement for such electricity energy services and will not be netted off of Delivered Energy for the purposes of determining amounts payable by Buyer in accordance with Section 5.1.

ARTICLE 5
PRICE AND PAYMENT TERMS

5.1 Energy Price

In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy, the Energy Price calculated in accordance with Schedule "B".

5.2 No Further Payment

The amount payable by Buyer as specified in Section 5.1 is the full and complete payment and consideration payable by Buyer for Delivered Energy and for Environmental Attributes.

5.3 Statements and Payment

(a) **Statements**

(i) Buyer will, by the 15th day of each month after the Buyer's COD, deliver to Seller a statement for the preceding month. The statement must indicate, among other things:

(A) the amount of, and price payable for, Delivered Energy for that month;

(B) any amount owing by Buyer in respect of a Non-Permitted Distribution/Transmission Constraint pursuant to Section 4.8;

(C) any Final Amounts owing by either Party to the other Party.

Where there has been any Delivered Energy purchased by Buyer in the period prior to Buyer's COD, the first statement following Buyer's COD shall also account for all amounts payable by Buyer to Seller for such period prior to Buyer's COD. The statement must set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed and be accompanied by sufficient data to enable Seller, acting reasonably, to satisfy itself as to the accuracy of the statement.

(ii) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the case of willful misstatement, fraud or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this Section within the 36 month period, which will be resolved in accordance with this EPA.

(iii) If Seller gives notice to Buyer of an error, omission or disputed amount on a statement as described in Section 5.3(a)(ii), Seller may direct Buyer to promptly produce new statements for the relevant month(s). The new statements will show the undisputed amount and disputed amount each in a separate statement or will otherwise separate the amounts in a single statement in a manner acceptable to Seller, acting reasonably.

(b) **Payment**

(i) Within 30 days after receipt of a statement delivered under Section 5.3(a), and subject to Section 5.5, Buyer will pay to Seller or Seller will pay to Buyer the amount set out in the statement, except to the extent Seller in good faith disputes all or part of the statement by notice to Buyer as described in Section 5.3(a)(ii).

(ii) If Seller disputes any portion of a statement, the applicable Party must pay the undisputed net amount payable by it pursuant to the statement or, if applicable, the new statement of the undisputed amount described in Section 5.3(a)(iii).

(iii) The Parties will endeavor to resolve any error, omission or disputed amount on a statement amount within 30 days of the notice described in Section 5.3(a)(ii).

(iv) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 2%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

(c) **Payment Calculations**

(i) For the purpose of all payment calculations under this EPA:

(A) all payment calculations will be rounded to the nearest cent; and

(B) Energy will be expressed in KWh rounded to two decimal places.

(ii) For the purpose of all payment calculations under this EPA, where CPI is to apply, if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(A) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(B) at any time ceases to publish or provide the CPI, then the provisions of Section 2.7 of Schedule "A" will apply;

(C) has not published the CPI for a relevant period at the time Buyer is required to provide Seller with a statement, Seller will prepare the invoice based on the CPI in effect at the time the invoice is issued and

when the CPI for the relevant period is published, Buyer will recalculate the invoice amounts in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(D) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then Buyer will recalculate the invoice amounts for the relevant period in the next succeeding invoice and will include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

5.4 Taxes

All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes, including GST and any successor thereto, which, if applicable, will be added to each statement and paid by Buyer.

5.5 Set-off

If Buyer and Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party will be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount will pay to the other Party the difference between the amounts owed, provided that this Section applies only to any purchase price for Delivered Energy and any Final Amount owing by either Party to the other Party. Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defenses which such Party has, or may be entitled to, arising from or related to this EPA.

5.6 Change in Law and GRA Cost Recovery

(a) If at any time after the Effective Date:

(i) the costs to Buyer of complying with its obligations under this EPA are, as a result of one or more Changes in Law, increased or decreased (including, for greater certainty, any increase of the obligations or risks of Buyer with respect to the Seller's Plant, but excluding any increase of the obligations or risks of Buyer with respect to the System Upgrades or New Interconnection Facilities); or

(ii) the costs to Buyer of complying with its obligations under this EPA which were of a category or type previously recovered under a General Rate Application are determined under a General Rate Application to no longer be approved for recovery from Buyer's customers in such General Rate Application;

then, to the extent that Buyer would not have incurred such costs except for the Seller's Project and/or the entering into of this EPA, the amount payable by Buyer as specified in Section 5.1 shall be adjusted by the amount necessary to reflect those changed costs which Buyer is unable to recover from Buyer's customers in a General Rate Application.

(b) For each relevant event in Section 5.6(a)(i) or 5.6(a)(ii), Buyer shall provide Seller with a statement setting out such information as is reasonably necessary to demonstrate that such an event has occurred, the reasonableness and necessity of the measures taken by

Buyer in relation to the event, its efforts to mitigate the costs associated with such event including reasonable efforts of Buyer to recover such costs from its customers in a General Rate Application, the nature and extent of any increase or decrease in the amount payable by Seller as specified in Section 5.1, and any such other information as may be reasonably requested by Seller.

(c) If in Seller's view there has been a Change in Law that may decrease Buyer's costs, Seller may request Buyer to demonstrate how such Change in Law has affected its costs under this EPA by providing the applicable information contemplated in Section 5.6(b).

(d) The payments between the Parties shall thereafter be adjusted effective as of the date such event in Section 5.6(a)(i) or 5.6(a)(ii) affects the costs of Buyer hereunder.

(e) If there is any Dispute between the Parties with respect to this Section 5.6, including as to the appropriate increase or decrease in any payments between the Parties under this Agreement, the Dispute shall be resolved in accordance with Article 12.

ARTICLE 6
ENVIRONMENTAL ATTRIBUTES

6.1 Environmental Attributes

Seller hereby transfers, assigns and sets over to Buyer all right, title and interest in and to the Environmental Attributes. Seller will ensure that all Environmental Attributes transferred to Buyer under this EPA are free and clear of all liens, claims, charges and encumbrances. Seller shall use commercially reasonable efforts to (i) provide information reasonably requested by Buyer in relation to such Environmental Attributes, including as may be required to allow Buyer to verify or certify that such Environmental Attributes exist or have been created and (ii) assist in having Seller's Plant certified, licensed, qualified or approved under any rules, regulations, programs or applicable Laws of any Governmental Authority or independent certification agency in respect of Environmental Attributes, provided that Buyer shall pay Seller all costs reasonably incurred by Seller in respect of the same. Any failure by Seller to exercise such commercially reasonable efforts under this Section 6.1 is a "material default" for the purposes of this EPA, and Buyer may terminate this EPA under Section 9.1(j).

ARTICLE 7
EPA ADMINISTRATION, RECORDS AND AUDITS

7.1 Records

Each of Buyer and Seller will prepare and maintain all Records, or duplicates of such Records, at Buyer's head office or local Yukon office or the Seller's Plant, as applicable, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed in writing between the Parties, for a period of not less than 7 years from the date on which each such Record is created. The Audit Parties may take copies of such Records for the purposes of an inspection or audit under Section 7.2.

7.2 Inspection and Audit Rights

For the sole purpose of verifying:

(a) compliance with this EPA;

(b) the accuracy of statements, supporting information and calculations delivered by a Party under this EPA;

(c) the qualification of the Seller's Plant and the Energy for the Environmental Certification; or

(d) the liability of Seller for System Upgrades Costs and New Interconnection Facilities Costs,

Buyer or Seller, as applicable, will, on reasonable prior written notice from either Party desiring to conduct an audit, provide the Audit Parties with prompt access during normal business hours to (i) in respect of Buyer, Buyer's records solely relating to this EPA, or (ii) in respect of Seller, Seller's Plant and all records relating to the Seller's Plant, including any Seller Confidential Information, as applicable, to enable the Audit Parties to conduct an inspection or audit thereof. The Audit Parties will exercise any access and audit rights under this Section in a manner that minimizes disruption to the operation of the Party subject to the audit. The audit rights contained in this Section 7.2 shall be subject to the limitations set forth in Section 5.3.

7.3 Seller Consents

Seller will promptly provide any consents required to enable any of the Audit Parties to make enquiries with any Governmental Authority or any Person administering the Environmental Certification concerning any or all of the following: (a) the qualification of the Seller's Plant and the Energy for Environmental Certification, the status of the Environmental Certification and copies of any audits, inspections or reports prepared in connection with the Environmental Certification; and (b) compliance by Seller with Laws and Permits applicable to the Seller's Plant.

ARTICLE 8
FIRST NATION CLAIMS

8.1 Notification of First Nation Claim

Given the ownership and location of the Project, Seller and Buyer do not expect any First Nation Claims. However, if Buyer or Seller receives or obtains evidence of a First Nations Claim, it will notify the other Party as soon as practicable.

8.2 Obligation to Consult

If Buyer receives, obtains evidence or becomes aware of a First Nations Claim, it may direct Seller, at Seller's cost, to:

(a) consult with the First Nations making the First Nation Claim, or, if requested by Buyer, assist Buyer in the consultation process;

(b) take any measures Seller deems necessary to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts provided the measures are consented to in advance by Buyer and the First Nations making the First Nation Claim; and

(c) provide regular written reports to Buyer concerning Seller's compliance with this Section, as may be reasonably requested by Buyer.

8.3 Seller Termination for First Nation Claim

At any time prior to Buyer's COD, if:

(a) within 60 days of Buyer receiving, obtaining evidence or becoming aware of a First Nations Claim, Buyer does not make a direction to Seller as contemplated in Section 8.2;

(b) Buyer notifies Seller in writing that it will not make a direction to Seller as contemplated in Section 8.2; or

(c) after consultation with the First Nations making the First Nation Claim it becomes clear that the measure(s) necessary for Seller to resolve the First Nation Claim or to address, prevent, mitigate, compensate or otherwise accommodate any Potential Impacts would, in Seller's discretion, impose a commercially unreasonable cost on Seller, or would require the consent of Buyer under this EPA or agreement by Buyer to amend this EPA in order to address any Potential Impacts and such consent or agreement to amend is not provided within 60 days after Seller's request to Buyer,

then Seller may terminate this EPA on notice to Buyer. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. A termination by Seller under this Section will, for all purposes of this EPA, be treated in the same manner as a termination by Seller under Section 9.3(c) of this EPA (including the obligations of Seller under Section 9.7). The termination of this EPA is the exclusive remedy to which Seller may be entitled to if Seller elects to terminate this EPA under this Section.

8.4 Buyer Termination for First Nation Claim

At any time prior to Buyer's COD, if Buyer receives, obtains evidence or becomes aware of a First Nations Claim, Buyer may, at its sole discretion, terminate this EPA on notice to Seller. Such termination will be effective 30 days after the date of delivery of such notice of termination unless otherwise agreed by the Parties. Upon a termination by Buyer under this Section 8.4, Seller shall reimburse Buyer for costs or liabilities described in Sections 9.7(a), (b) and (c). The reimbursement by Seller of such costs or liabilities, the indemnification by Seller contemplated in Section 8.5 and the termination of this EPA are the exclusive remedies to which Buyer may be entitled to if Buyer elects to terminate this EPA under this Section.

8.5 Seller Indemnity for First Nation Claim

Seller shall indemnify and hold Buyer and its Affiliates harmless from any and all claims, damages, costs, expenses, or liabilities whatsoever incurred by Buyer and its Affiliates in relation to such First Nation Claim and such indemnity shall survive termination of this EPA.

ARTICLE 9
TERMINATION

9.1 Termination by Buyer

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA by notice to Seller if:

(a) Seller's COD does not occur within 730 days following Target Seller's COD for any reason whatsoever (including Force Majeure), provided that Buyer may terminate this EPA under this provision only if Buyer delivers a termination notice prior to Seller's COD; or

(b) at any time after Buyer's COD, Seller fails to deliver at least an average of 25% of the aggregate Projected Monthly Energy as set out in Schedule "E" to Buyer over all hours in a period of 730 continuous days for any reason whatsoever (including Force Majeure, a Distribution/Transmission Constraint), but excluding a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(c) at any time after Buyer's COD, Buyer is unable to accept delivery of Energy at the POI for a period of 730 continuous days due to Force Majeure invoked by Buyer or a Distribution/ Transmission Constraint other than a Non-Permitted Distribution/ Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Seller breaches Section 4.5; or

(e) Seller fails to complete any application, payment, filing, study, document or other step in the process for interconnecting the Seller's Plant to the Distribution System, Transmission System or New Interconnection Facilities, as applicable, in accordance with the requirements of, and within the time limits, including any cure periods, specified by Buyer, and such failure could reasonably be expected to have an adverse impact on Buyer or any third party; or

(f) any System Interconnection Study Report completed after the Effective Date contains information that is inconsistent with the description of the Seller's Plant in Schedule "B" and Seller has not received Buyer's consent under Section 3.3 for the change to Schedule "B"; or

(g) Seller is Bankrupt or Insolvent; or

(h) Seller, as a result of an act or omission of Seller, ceases to be exempt from regulation as a "public utility" as defined in the *Public Utilities Act* with respect to the Seller's Plant and the sale of Energy to Buyer under this EPA, and the loss of such exemption could reasonably be expected to have an adverse effect on the benefit to Buyer of this EPA; or

(i) an amount due and payable by Seller to Buyer under this EPA remains unpaid for 30 days after its due date and such default has not been cured within 30 days after Buyer has given notice of the default to Seller; or

(j) Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Buyer to Seller of the default Seller has cured the default or, if the default cannot be cured within that 30 day period, Seller demonstrates to the reasonable satisfaction of Buyer that Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any purported Assignment of this EPA without the consent of Buyer.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Seller.

9.2 Notice of Termination Event

Seller will notify Buyer promptly if Seller is Bankrupt or Insolvent or if there is a material risk that Seller will become Bankrupt or Insolvent or if Seller has defaulted under any agreement with a Facility Lender or if any Permit or land tenure agreement for the Seller's Plant is terminated or expires.

9.3 Termination by Seller

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Seller may have under this EPA or at law or in equity in respect of any of the following events, Seller may terminate this EPA by notice to Buyer if:

(a) after Buyer's COD, Buyer has not accepted delivery of Energy for a period of 730 continuous days due to an event described in Section 4.4 or any event of Force Majeure and Seller is not entitled to receive any payment pursuant to Section 4.8 in respect of that period; or

(b) the Seller's Plant has suffered major damage where the cost to repair the damage exceeds the net present value (using the Present Value Rate) of the expected revenues under the EPA for the remainder of the Term less the net present value (using the Present Value Rate) of the estimated operating and maintenance costs for the Seller's Plant for the remainder of the Term; or

(c) Seller has been unable to achieve Seller's COD for a period of 730 days after Target Seller's COD or has been unable to deliver Energy to the POI for a period of 730 continuous days after Seller's COD in either case solely as a result of Force Majeure invoked by Seller or a Distribution/Transmission Constraint other than a Non-Permitted Distribution/Transmission Constraint for which Seller is entitled to receive payment under Section 4.8; or

(d) Buyer is Bankrupt or Insolvent; or

(e) except where an amount has been disputed in the manner specified in Section 5.3(a)(ii), an amount due and payable by Buyer to Seller under this EPA remains unpaid for 30 days

after its due date and such default has not been cured within 30 days after Seller has given notice of the default to Buyer; or

(f) Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by Seller to Buyer of the default Buyer has cured the default or, if the default cannot be cured within that 30 day period, Buyer demonstrates to the reasonable satisfaction of Seller that Buyer is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time.

Any termination pursuant to this Section will be effective immediately upon delivery of the notice of termination to Buyer.

9.4 Termination by Buyer for Convenience

In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA and in addition to all other rights and remedies Buyer may have under this EPA or at law or in equity in respect of any of the following events, Buyer may terminate this EPA for convenience upon 90 days prior notice to Seller.

9.5 Effect of Termination

Upon expiry of the Term or earlier termination of this EPA in accordance with its terms:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of this EPA and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination or that are stated to arise on termination of this EPA, subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA;

(b) both Parties will remain bound by Section 3.5 with respect to the satisfaction of residual obligations for the period prior to termination or that are specified to arise on, or continue following, termination, and Sections 12.1 and 13.1 associated with Delivered Energy prior to termination of this EPA; and

(c) Seller will remain bound by Sections 7.1 and 7.2 for a period of 36 months following expiry or termination of this EPA;

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

9.6 Buyer Payment on Termination

If Seller terminates this EPA under any of Sections 9.3(d), 9.3(e) or 9.3(f) or Buyer terminates this EPA for convenience under Section 9.4, Buyer will pay to Seller an amount equal to the applicable Termination Payment due at the time of termination determined in accordance with Schedule "F".

9.7 Seller Payment on Termination

If Buyer terminates this EPA on or before 90 days after Seller's COD or Seller terminates this EPA on or before Buyer's COD under any of Sections 9.3(a), 9.3(b) or 9.3(c), Seller will, within 30 days after receipt of an invoice from Buyer, reimburse Buyer for:

(a) all System Upgrade Costs and New Interconnection Facilities Costs incurred by Buyer, or which Buyer has become contractually obligated to pay, prior to the termination of the EPA including System Upgrade Costs and New Interconnection Facilities Costs Seller would otherwise be responsible for under Section 3.5;

(b) any incremental liability for System Upgrade Costs and New Interconnection Facilities Costs which Buyer will incur as a result of the termination of this EPA; and

(c) any System Upgrade Costs and New Interconnection Facilities Costs which Seller is responsible for under any reimbursement agreement pursuant to Section 3.3.

9.8 Calculation and Payment

Buyer will pay any amount which it owes under Section 9.6 within 30 Business Days after the date of delivery of an invoice by Seller to Buyer. Any amounts owing by Seller to Buyer under this EPA will be netted against any amount owing by Buyer to Seller under Section 9.6.

9.9 Exclusive Remedies

Payment by Buyer of the amount determined under Section 9.6 is the exclusive remedy to which Seller is entitled, and Buyer's limit of liability, for termination of this EPA by Seller pursuant to any of Sections 9.3(d), 9.3(e) or 9.3(f). Subject to Section 9.4 and 9.7, termination of this EPA is the exclusive remedy to which Buyer or Seller, as the case may be, is entitled if Buyer or Seller elects to exercise its right to terminate this EPA under any of Section 9.1, 9.3(a), 9.3(b) or 9.3(c). For greater certainty, subject to Section 9.4 and 9.7, Seller will not be required to pay any termination payment on termination by Buyer of this EPA. Neither Party will have any right to terminate this EPA except as expressly set out herein.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Seller's Representations

Seller represents and warrants to Buyer, and acknowledges that Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) Seller is a corporation formed under the laws of _____, is validly existing and is in good standing under the laws of ____, is lawfully authorized to carry on business in _____, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Seller enforceable against Seller in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Seller.

10.2 Buyer's Representations

Buyer represents and warrants to Seller, and acknowledges that Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) Buyer is a corporation formed under the laws of the Yukon, is validly existing and is in good standing under the laws of the Yukon, is lawfully authorized to carry on business in the Yukon, and has full corporate power, capacity and authority to enter into and to perform its obligations under this EPA;

(b) this EPA constitutes a valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms; and

(c) this EPA has been duly authorized, executed and delivered by Buyer.

ARTICLE 11
LIABILITY LIMITATIONS

11.1 Limit of Liability

Buyer's liability for damages for any failure to take or pay for Delivered Energy under this EPA is limited to the amount payable by Buyer for that Delivered Energy under Article 5, amounts owing under Sections 4.8 and any interest thereon calculated under this EPA.

11.2 Consequential Damages

Neither Party will be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages with respect to, arising out of, relating to or in any way connected with a Party's performance or non-performance under this EPA.

ARTICLE 12
DISPUTES

12.1 Dispute Resolution Procedure

Any dispute, controversy or claim arising out of or relating to this EPA ("**Dispute**") shall be exclusively and finally resolved in accordance with the dispute resolution procedure set forth in this Article 12 (the "**Dispute Resolution Procedure**").

12.2 Commencement of the Dispute Resolution Procedure

The Parties shall make reasonable efforts to first resolve any Dispute. If a Dispute cannot be resolved by the Parties, then either Party may initiate the Dispute Resolution Procedure by giving notice of the Dispute to the other Party (the "**Notice of Dispute**"). The Notice of Dispute shall contain a brief statement of the nature of the Dispute, set out the relief requested, and request that the Dispute Resolution Procedure be commenced.

12.3 Negotiations

Upon the submission of a Notice of Dispute pursuant to Section 12.2, each of the Parties shall refer the Dispute to a designated senior management executive with the authority to negotiate a

settlement of the Dispute for that Party (the "**Senior Management Executives**"). The Senior Management Executives of the Parties shall attempt to resolve the Dispute within 30 days from the date on which the Notice of Dispute was issued, or such longer period as the Senior Management Executives may otherwise unanimously agree. If the Senior Management Executives unanimously agree upon a resolution of the Dispute, such resolution shall be memorialized in a written settlement agreement mutually acceptable to the Parties and shall be binding on the Parties.

12.4 Arbitration

If a Dispute is not resolved by Senior Management Executives within 30 days from receipt of a Notice of Dispute (or such longer period as the Senior Management Executives may otherwise agree in writing), the Dispute shall, at the request of either Party, be resolved by binding arbitration under the Rules of Arbitration of the International Chamber of Commerce (the "**ICC Rules**"), except to the extent of conflicts between the ICC Rules and the provisions of this EPA, in which event the provisions of this EPA shall prevail. The following provisions shall apply to an arbitration commenced pursuant to this Section 12.4:

(a) the number of arbitrators shall be one;

(b) the place, or legal seat, of the arbitration shall be Whitehorse, Yukon;

(c) the language to be used in the arbitral proceedings shall be English;

(d) all awards issued by the arbitrator shall be final, non-appealable and binding on the Parties. Any award may be filed in any court of competent jurisdiction and may be enforced by a Party as a final judgment in such court. The Parties expressly waive, to the maximum extent permitted by law, any right of appeal of any award or reference of any matter to any court, other than as may be necessary to recognize or enforce an award;

(e) the arbitrator shall be guided by the International Bar Association's Rules on the Taking of Evidence in International Commercial Arbitration;

(f) the Parties shall request that the arbitrator render its final award within 12 months of the commencement of the arbitration, or as soon as possible thereafter, provided that no award shall be invalid if it is not rendered within the time period herein specified;

(g) any award for monetary damages shall be made and payable in Canadian Dollars and may include interest from the date of any breach or violation of this EPA until paid in full at the rate determined by the arbitrator;

(h) the Parties agree that any arbitration carried out hereunder shall be kept private and confidential, and that the existence of the proceedings and any element of it (including all awards, the identity of the Parties and all witnesses and experts, all materials created for the purposes of the arbitration, all testimony or other oral submissions, and all documents produced by a Party that were not already in the possession of the other Party) shall be kept confidential, except (i) with the consent of the Parties, (ii) to the extent disclosure may be lawfully required in bona fide judicial proceedings relating to the arbitration, (iii) where disclosure is lawfully required by a legal duty, and (iv) where such information is already in the public domain other than as a result of a breach of this clause. The Parties

also agree not to use any information disclosed to them during the arbitration for any purpose other than in connection with the arbitration;

(i) where a Dispute relates to the EPA, the Parties shall agree to consolidate the matters in Dispute under such agreements in a single arbitration;

(j) the Parties agree that during the resolution of a Dispute pursuant to this Article 12, the Parties shall continue to perform their obligations under this EPA, provided that such performance shall be without prejudice to the rights and remedies of the Parties and shall not be read or construed as a waiver of a Party's right to claim for recovery of any loss, costs, expenses or damages suffered as a result of the continued performance of this EPA; and

(k) each Party will be responsible for its own costs under this Article 12, subject to the award of an arbitrator.

ARTICLE 13
CONFIDENTIALITY

13.1 Confidentiality

(a) **Additional Confidentiality Obligation** - During the Term and for two years thereafter:

(i) Buyer will treat as confidential, and will not disclose to any third Person, Seller Confidential Information, and

(ii) Seller will treat as confidential, and will not disclose to any third Person, Buyer Confidential Information.

(b) **Disclosure of Confidential Information** - Notwithstanding Section 13.1(a) above:

(i) Seller may also disclose Buyer Confidential Information and Buyer may disclose Seller Confidential information in the following circumstances:

(A) disclosures expressly authorized under this EPA or otherwise set out in this EPA;

(B) disclosures to enable a Party to fulfill its obligations under the EPA;

(C) disclosure in any arbitration or legal proceedings for the enforcement of the EPA;

(D) disclosure to the Party's directors, officers, employees, Facility Lenders, consultants and advisors, and purchasers of the Environmental Attributes, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(E) subject to Section 13.1(b)(ii)(D), disclosure required to be made by a Party by an order of a court, a regulatory agency or a tribunal or under any law, regulatory requirements or any requirement of any stock exchange that is binding upon a Party, provided that (i) to the extent

reasonably practicable, the Party intending to make such disclosure gives reasonable notice to the other Party before make the disclosure, and (ii) limits the disclosure to that required by the applicable order, Laws or regulatory or stock exchange requirement;

(F) disclosure to a third Person if such information was known by that third Person before disclosure by Buyer or Seller, as the case may be, provided the third Person did not know of the information as a result of a breach of the non-disclosure obligations in this EPA; or

(G) disclosure with the consent of Buyer, in the case of Buyer Confidential Information, or Seller, in the case of Seller Confidential Information.

(ii) Buyer may disclose Seller Confidential Information in the following circumstances:

(A) disclosure to Buyer's Affiliates or to a third Person, and their respective employees, consultants and advisors, for the purpose of reselling or marketing any Energy, including disclosure of Seller Confidential Information by such Affiliate or third Person to those who have purchased or may purchase the Energy;

(B) for purposes other than those described in Section 13.1(b)(i), to Buyer's Affiliates and to any directors, officers, employees, consultants and advisors of any Affiliates, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality;

(C) to any ministers, deputy ministers, servants or employees of the Yukon or the federal government, provided each of them is advised of the confidential nature of the information and agrees to respect such confidentiality; or

(D) disclosure in any regulatory proceeding, whether related to this EPA or not, to the extent that Buyer considers disclosure is necessary or desirable to support its position in such proceeding.

ARTICLE 14
FORCE MAJEURE

14.1 Force Majeure

(a) If there is a Force Majeure affecting a Party's ability to perform an obligation under this EPA, and that Party wishes to declare a Force Majeure, that Party will promptly notify the other Party of the Force Majeure. The notice of Force Majeure must identify the nature of the Force Majeure, the date the Force Majeure commenced, the expected duration of the Force Majeure, and the particular obligations affected by the Force Majeure. If (i) a notice of Force Majeure is provided in accordance with this Section, (ii) the event in question is in fact an event of Force Majeure as defined in this EPA, and (iii) the event of Force Majeure commenced on the commencement date in the notice of Force

Majeure, then the Force Majeure will be deemed to have been invoked as of the commencement date stated in the notice.

(b) Neither Party will be in default of any obligation under this EPA if a Party is unable to perform that obligation due to an event or circumstance of Force Majeure, provided notice is delivered in accordance with this Section and the circumstances are, in fact, an event or circumstance of Force Majeure.

(c) Subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure. The Party invoking Force Majeure will make commercially reasonable efforts to promptly remove the Force Majeure and will promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure and will give prompt notice of the end of the Force Majeure.

ARTICLE 15
GENERAL PROVISIONS

15.1 Independence

The Parties are independent contractors, and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

15.2 Enurement

This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

15.3 Assignment

(a) Seller may not assign this EPA except with the prior consent of Buyer, which consent may not be unreasonably withheld, conditioned or delayed provided such Assignment is to a Facility Lender. Any Assignment (other than an Assignment to a Facility Lender) is subject to the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of Seller under this EPA arising both before and after the Assignment, and providing the representations and warranties set out in Section 10.1 effective as at the time of Assignment, and Seller not being in default under this EPA. Unless agreed to in writing by Buyer, Seller shall remain jointly and severally liable with the assignee for all obligations of Seller under this EPA.

(b) Any request by Seller for Buyer's consent under Section 15.3(a) must be delivered to Buyer not less than 30 days before the date of the proposed Assignment. A request under this Section must be accompanied by such information as reasonably required by Buyer to assess the request for consent including the name, address and ownership structure of the assignee, details of any consultation with First Nations that may be impacted by the Seller's Plant or the Assignment with respect to the proposed Assignment, list of the directors and officers of the assignee and information concerning the assignee's operations, experience and financial status.

(c) If Seller seeks consent to Assign this EPA to a Facility Lender, Buyer may require, as a condition of its consent to the Assignment, that Seller and the Facility Lender enter into a

Lender Consent Agreement with Buyer containing customary provisions. If required by a Facility Lender, Buyer will enter into a Lender Consent Agreement with the Facility Lender and Seller containing customary provisions. Seller will reimburse Buyer for all costs reasonably incurred by Buyer in connection with any request by Seller for Buyer's consent pursuant to Section 15.3(a).

15.4 Entire Agreement

This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA. **[Note to Developers – as described in the SOP Rules, to the extent that a Project interconnects into AEY's portion of the YIS, there may be additional agreements required between AEY and Seller, in which case this section may need to be modified]**

15.5 Amendment

This EPA may not be amended except by an agreement in writing signed by both Parties.

15.6 No Waiver

Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

15.7 Notices

Any notice, consent, waiver, declaration, request for approval or other request, statement or bill that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address for that Party stated in Schedule "A" and:

(a) notices under Section 14.1, Article 8 and Article 9 must be delivered by hand or by a courier service during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day;

(b) all notices other than notices described in Section 15.7(a) may be delivered by email during normal business hours on a Business Day and a notice so delivered will be deemed to have been delivered on that Business Day; and

(c) either Party may change its address for notices under Section 3 of Schedule "A" to this EPA by notice to the other Party.

15.8 Interconnection Notices

Nothing in the System Interconnection Guidelines and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA,

except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the System Interconnection Guidelines will constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA.

15.9 Commodity Contract/Forward Contract

The Parties agree and intend that this EPA constitutes an "eligible financial contract" under the *Bankruptcy and Insolvency Act* (Canada) and *Companies' Creditors Arrangement Act* (Canada).

15.10 Further Assurances

Each Party will, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA including, in the case of Seller, completing any registration process required in respect of Environmental Attributes as requested by Buyer.

15.11 Severability

Any provision of this EPA which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

15.12 Counterparts

This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

[Signature Page Follows]

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA effective as of the date set out on page one of this EPA.

[SELLER]	**[UTILITY - BUYER]**
Per: _____	Per: _____
[Name]	[Name]
[Title]	[Title]
Per: _____	Per: _____
[Name]	[Name]
[Title]	[Title]

SCHEDULE "A"

DEFINITIONS AND INTERPRETATION

1. DEFINITIONS

References in a Schedule to a section or Section mean a section or Section of this EPA, and not a Schedule, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1.1 "**Affiliate**" means, with respect to any Party or any third Person, any Person directly or indirectly Controlled by, Controlling, or under common Control with, such Party or the third Person.

1.2 "**Annual Operating Plan**" means a 12-month operating plan for the Seller's Plant that includes for term of each operating plan, (a) a schedule of the expected total deliveries of Energy at the POI in each month and (b) a schedule of any Planned Outages of the Seller's Plant expected by Seller. The Annual Operating Plan will be consistent with Good Industry Practice and shall be substantially in the form attached hereto as Schedule "C", subject to such modifications thereto as may be reasonably required by Buyer.

1.3 "**Application**" means the application and all supporting documents and information with respect to the Seller's Plant filed by Seller with Buyer in the Standing Offer Program.

1.4 "**Assign**" or "**Assignment**" means to assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term and, without limiting the foregoing, each of the following is deemed to be an Assignment of this EPA by Seller:

(a) any sale or other disposition of all or a substantial part of Seller's ownership interest in the Seller's Plant, or of all or any interest of Seller in this EPA or revenue derived from this EPA;

(b) any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant or Seller's ownership interest therein; and

(c) any change of Control, merger, amalgamation or reorganization of Seller.

1.5 "**Audit Parties**" means the applicable Party conducting an audit under this EPA and its Affiliates, representatives, consultants, advisors and any other third Person retained in respect of the applicable audit.

1.6 "**Bankrupt or Insolvent**" means, with respect to a Person:

(a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it;

(b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law;

(c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy;

(d) the Person has voluntarily suspended the transaction of its usual business; or

(e) a court of competent jurisdiction has issued an order declaring the Person bankrupt or insolvent.

1.7 "**Business Day**" means any calendar day which is not a Saturday, Sunday or Yukon statutory holiday.

1.8 "**Buyer**" means _____ and its successors and permitted assigns.

1.9 "**Buyer Confidential Information**" means technical or commercial information disclosed by Buyer to Seller that Buyer directs, and clearly marks, as confidential, including the System Interconnection Guidelines and this EPA but excluding information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Seller, or (ii) is known to Seller before disclosure to it by Buyer, or becomes known to Seller, thereafter by way of disclosure to Seller by any other Person who is not under an obligation of confidentiality with respect thereto.

1.10 "**Buyer's COD**" shall occur when the System Upgrades have been completed and Buyer provides a notice of completion of the same to Seller.

1.11 "**Change in Law**" means (a) the enactment, adoption, promulgation, modification or repeal of any applicable Laws or any change in the interpretation or administration of any applicable Laws resulting from a decision of a Governmental Authority which occurs after the Effective Date; but in each case excluding a Change in Law relating to income tax, or (b) the requirement for a new Permit (including due to a change in the circumstances in which a Permit is required), a change in the terms of any Permit after the date such Permit is granted, or any change in the interpretation or administration of any Permits resulting from a decision of a Governmental Authority.

1.12 "**Condition Date**" means the date specified as such in Schedule "B".

1.13 "**Conditions Precedent**" means those conditions precedent set out in Schedule "B".

1.14 "**Control**" of any Person means:

(a) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or Persons performing similar functions;

(b) ownership of 50% or more of the equity or beneficial interest in that Person; or

(c) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

1.15 "**CPI**" means the "Canada All Items (Not Seasonally Adjusted)" Consumer Price Index as published by Statistics Canada or any successor agency thereto.

1.16 "**Delivered Energy**" means in each month after Buyer's COD the amount of Energy delivered by Seller at the POI in that month as recorded by Buyer's Meter less the applicable Line Losses.

1.17 "**Development Progress Report**" means a report describing the progress of the financing, design, engineering, construction, Interconnection, and commissioning of the Seller's Plant, that is in form and content acceptable to Buyer, acting reasonably.

1.18 "**Discretion**" (whether or not capitalized) means sole, absolute and unfettered discretion unless this EPA expressly states otherwise.

1.19 "**Dispatch/Turn-Down**" means for Seller to turn down or shut off the Seller's Plant.

1.20 "**Dispatch/Turn-Down Deemed Energy**" has the meaning given to such term in Section 4.9(b)(i).

1.21 "**Distribution System**" means the distribution, protection, control and communication facilities in the Yukon that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35 kilovolts or less, and includes all additions and modifications thereto and repairs or replacements thereof.

1.22 "**Distribution/Transmission Constraint**" means any disconnection of the Seller's Plant from the Distribution System or Transmission System, or any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System preventing or limiting deliveries of Energy at the POI or within the Distribution System or Transmission System or any direction from Buyer to reduce generation of the Seller's Plant as a result of any outage, suspension, constraint or curtailment in the operation of the Distribution System or Transmission System.

1.23 "**Effective Date**" shall mean the date on which all Conditions Precedent have been satisfied or waived in accordance with Section 2.1.

1.24 "**Electrical Grid**" means the electrical grid into which the Seller's Plant will be interconnected, as identified in Schedule "B"**.**

1.25 "**Eligible Clean Energy**" means wind, hydro, geothermal, biomass and solar energy sources permitted under the IPP Policy for the SOP generated by a Project located in Yukon which is directly connected into the YIS or the WLG through the New Interconnection Facilities.

1.26 "**Energy**" means all electrical energy expressed in KWh generated by the Seller's Plant, excluding electrical energy generated by the Seller's Plant which is required to service the Seller's Plant Load.

1.27 "**Energy Price**" has the meaning given to such term in Schedule "B".

1.28 "**Environmental Attributes**" means the following as attributable to Energy delivered to Buyer under this EPA:

(a) all attributes directly associated with, or that may be derived from, the Energy delivered to Buyer under this EPA having decreased environmental impacts relative to certain other generation facilities or technologies including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable;

(b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy delivered to Buyer under this EPA;

(c) any credit, reduction right, off-set, allowance, allocated pollution right, certificate or other unit of any kind whatsoever whether or not tradeable resulting from or otherwise related to the reduction, removal, or sequestration of emissions at or from the Seller's Plant; and

(d) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing, but for certainty not including:

i. benefits or proceeds from environmental incentive programs offered by Governmental Authorities that do not require a transfer of the attributes in (a) to (c) above; and

ii. benefits or proceeds from social programs, including programs relating to northern or rural development, employment or skills training, or First Nations, that do not require a transfer of the attributes in Sections (a) to (c) above.

1.29 "**Environmental Certification**" means any certification Buyer requires Seller to obtain under Section 6.1.

1.30 "**Facility Lender**" means any lender(s) providing any debt financing or debt hedging facilities for the design, engineering, construction and/or operation of the Seller's Plant and any successors or assigns thereto and any Person taking any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's Plant.

1.31 "**Final Amount**" means an amount owing by either Party to the other Party under this EPA, including as a result of a breach of this EPA, where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award under Section 12.1 of this EPA or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

1.32 "**First Nation Claim**" means a legal claim or proceeding or written threat to commence a legal claim or proceeding from or on behalf of First Nations where such claim or threat alleges a breach or potential breach of, or an impact to: any First Nations' Treaty rights, rights under a Settlement Agreement (as that term is defined in the Yukon Umbrella Final Agreement), or rights under section 35 of the *Constitution Act*, 1982, by (a) this EPA, (b) the Seller's Plant, (c) the Interconnection or any works related to the Interconnection, or (d) any authorization granted by the Yukon or federal government relating to the Seller's Plant and its operations.

1.33 "**First Nations**" means any one of the 14 First Nations in the Yukon.

1.34 "**Force Majeure**" means any event or circumstance not within the control of the Party, or any of its Affiliates, claiming Force Majeure, but does not include:

(a) any economic hardship or lack of money, credit or markets;

(b) an event or circumstance that is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws;

(c) a mechanical breakdown or control system hardware or software failure, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the breakdown or failure was caused by a latent defect in the design or manufacture of the equipment, hardware or software, which could not reasonably have been identified by normal inspection or testing of the equipment, hardware or software;

(d) an event or circumstance caused by a breach of, or default under, this EPA or a willful or negligent act or omission by the Party seeking to invoke Force Majeure;

(e) any Distribution/Transmission Constraint unless such event is caused by an event or circumstance not within the control of Buyer; or

(f) any acts or omissions of: (i) any Affiliate, employee, director, officer, agent or other representative of the Party invoking Force Majeure; (ii) any vendor, supplier, contractor, subcontractor, consultant or customer of or to the Party invoking Force Majeure; or (iii) any other Person for whom the Party invoking Force Majeure is responsible at law, unless the act or omission is caused by an event or circumstance that would constitute Force Majeure if the Person described above was a party to this EPA in place of a Party invoking Force Majeure.

1.35 "**Forced Outage**" means the immediate removal of one or more generating units of the Seller's Plant or transmission or distribution infrastructure of the Seller's Plant from service in response to equipment alarms or any damage identified during a Planned Outage or Maintenance Outage requiring extension of those Planned Outage or Maintenance Outage.

1.36 "**General Rate Application**" means any application, review, process, or procedure in which the YUB sets and approves rates to be charged by Buyer for the supply of the service for which it is franchised in accordance with the *Public Utilities Act*.

1.37 "**Good Industry Practice**" means:

(a) in respect of Buyer, any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the Yukon; and provided that Buyer shall be in compliance with Good Industry Practice in respect of any equipment comprising the Distribution System or Transmission System, if it operates such equipment in accordance with all applicable original equipment manufacturer guidelines and requirements provided to Buyer by supplier of such equipment; and

(b) in respect of Seller, any of the practices, methods and acts engaged in or approved by a significant portion of the electric generation industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in

light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided such practices, methods and acts are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in Western Canada.

1.38 "**Governmental Authority**" means any federal, provincial, local or foreign government or any of their boards or agencies, or any regulatory authority other than Buyer and Seller and entities controlled by Buyer or Seller.

1.39 "**GST**" means the goods and services tax imposed under the *Excise Tax Act* (Canada) as that Act may be amended or replaced from time to time.

1.40 "**Interconnection"** means the POI.

1.41 "**IPP Policy**" has the meaning given to such term in the recitals to this EPA.

1.42 "**Joint Operating Procedure**" means the joint operating procedure attached as Schedule "H" as may be modified by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.43 "**KW**" means kilowatt.

1.44 "**KWh**" means kilowatt-hour.

1.45 "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority in effect from time to time.

1.46 "**Lender Consent Agreement**" means a lender consent agreement in the form and substance acceptable to Buyer, acting reasonably.

1.47 "**Line Losses**" means losses of electricity associated with the transmission and transformation of Energy and other electricity, if applicable, from the Seller's Plant to the POI that are recorded by the Meter or reasonably estimated by Buyer.

1.48 "**Line Loss Methodology**" means the Line Loss Methodology set forth in the System Interconnection Study Report for the purposes of this Project.

1.49 "**Maintenance Outage**" means any outage of Buyer's Distribution System or Transmission System or the Seller's Plant that is not a Planned Outage or a Forced Outage that typically has a flexible start and end time and of shorter duration than a Planned Outage.

1.50 "**Meter**" means a meter owned by Buyer that is: (a) capable of accurately measuring the quantity of Energy generated by the Seller's Plant and delivered to the POI independent of all other generation equipment or facilities, (b) capable of being remotely interrogated; and (b) calibrated to measure on an hourly basis the quantity of Energy delivered by Seller to the POI.

1.51 "**Monthly Energy Shortfall Payment**" has the meaning given to such term in Schedule "E".

1.52 "**New Interconnection Facilities**" means those additions, modifications and upgrades required to interconnect the Project to the Electrical Grid which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any System Upgrades.

1.53 "**New Interconnection Facilities Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the New Interconnection Facilities, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.54 "**Non-Permitted Distribution/Transmission Constraint**" has the meaning given to such term in Section 4.8(a).

1.55 "**Outage**" means a Forced Outage, Maintenance Outage, or Planned Outage of Buyer's Distribution System or Transmission System or Seller's Plant.

1.56 "**Outage Notice**" means a notification of any Outage or revised notification of any Outage required to be delivered by Seller to Buyer or Buyer to Seller under this EPA that describes the timing, frequency, nature and duration of the Outage and that is in a format that may be prescribed by Buyer from time to time.

1.57 "**Party**" means Buyer or Seller, and "**Parties**" means both Buyer and Seller.

1.58 "**Permits**" means permits, certificates, licences, approvals and other authorizations issued by any Governmental Authorities as may be required for the design, construction, ownership, operation, maintenance and decommissioning of (i) the Seller's Plant and the delivery of Energy to the POI, and (ii) the System Upgrades and the New Interconnection Facilities.

1.59 "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

1.60 "**Planned Outage**" means an outage that is scheduled well in advance for purposes of inspections, maintenance, or repair of Buyer's Distribution System or Transmission System or Seller's Plant, that typically has a predetermined duration and scope of work, occurs only once or twice per year, and may last for several days.

1.61 "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Distribution System or Transmission System, as identified on the Single Line Diagram.

1.62 "**Potential Impacts**" means any adverse or potentially adverse impact on the established or potential aboriginal rights (including title) of First Nations as a result of:

(a) this EPA;

(b) the Project;

(c) the interconnection of the Seller's Plant to the Distribution System or Transmission System; or

(d) any activities directly related to the Seller's Plant that enable Seller to comply with its obligations under this EPA that are carried out by Seller, any Affiliate, consultant or contractor of Seller, or any other Person for whom Seller is responsible at law.

1.63 "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

1.64 "**Present Value Rate**" means the annual yield on a Government of Canada bond having a term and maturity date that most closely matches the remaining Term (as at the date of the applicable calculation) and expiry date of this EPA, plus 3%.

1.65 "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Whitehorse, Yukon, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

1.66 "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

1.67 "**Project Cluster**" means two or more existing or proposed Projects under the SOP Rules that Buyer determines in its Discretion are so closely related to each other that they should be considered a project cluster for the purposes of the Standing Offer Program.

1.68 "**Project Energy Volume**" (in KWh) means the maximum annual Energy which Buyer may sell to Seller from the Project in any calendar year as set out in Schedule "B"; provided that where the Term does not commence on January 1, such amount shall be prorated for the first and last contract year which do not reflect a full calendar year. **[Note to Developers – this amount will be set when the EPA is executed. It will be determined based on the annual energy volume which is expected to be generated by the Project in a calendar year determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Nameplate Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]**

1.69 "**Project Standards**" means:

(a) all applicable Laws;

(b) the terms and conditions of all Permits, including land tenure agreements, issued in connection with the Seller's Plant;

(c) Good Industry Practice;

(d) the description of the Seller's Plant in Schedule "B";

(e) the requirement that Energy must qualify as Eligible Clean Energy; and

(f) the terms and conditions of this EPA (including the System Interconnection Guidelines).

1.70 "**Public Utilities Act**" means the *Public Utilities Act* (Yukon) and any successor or replacement legislation.

1.71 "**Records**" means all records and logs required to properly administer this EPA, including:

(a) Energy generation records and operating logs;

(b) Meter readings;

(c) maintenance reports;

(d) invoice support records;

(e) documents concerning compliance with Project Standards, but excluding any such documents that are protected by solicitor-client privilege;

(f) records related to System Upgrade Costs and New Interconnection Facilities Costs;

(g) all information reasonably required to establish the amount of Energy Seller could have sold during a Distribution/Transmission Constraint including logs of all Outages of the Seller's Plant and other reductions in Energy output (specifying the date, time, duration and reasons for each such outage and each reduction in Energy output); and

(h) information relating to the Environmental Certification, information relating to the existence, nature and quality of Environmental Attributes, information required for the purposes of any Environmental Attributes or energy certification or tracking system, and any other information Buyer requires to enable it or any of its Affiliates to obtain and realize the benefit of the Environmental Attributes,

all consistent with Good Industry Practice.

1.72 "**Regulatory Agency Authorizations**" means the issuance of those Permits which are specified as required for the Project in the YESAB assessment report recommendation to proceed issued in respect of the Project.

1.73 "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

1.74 "**Seller Confidential Information**" means any of Seller's confidential technical or financial information provided by Seller to Buyer in confidence with express written notice to Buyer of the confidential nature of the information, but excluding:

(a) this EPA; and

(b) information that (i) is or becomes in the public domain, other than as a result of a breach of this EPA by Buyer, or (ii) is known to Buyer before disclosure to it by Seller, or becomes known to Buyer thereafter by way of disclosure to Buyer by any other Person who is not under an obligation of confidentiality with respect thereto.

1.75 "**Seller's COD**" means the commercial operation date of Seller's Plant which is the date on which all of the following conditions have been satisfied in respect of the Seller's Plant:

(a) Seller has obtained all Permits required for the construction, commissioning, and operation of the Seller's Plant and all such Permits are in full force and effect;

(b) the Seller's Plant has been fully constructed in accordance with the Project Standards;

(c) Seller is not: (A) Bankrupt or Insolvent; (B) in default of any payment obligation or requirement to post security under this EPA; (C) in material default of any of its other covenants, representations, warranties or obligations under this EPA; or (D) in material default under any Permit or Law applicable to the construction, commissioning or operation of the Seller's Plant or under any land tenure agreement for the site on which the Seller's Plant is located;

(d) a Meter has been installed at the POI in accordance with Section 3.6 of this EPA;

(e) Seller has delivered to Buyer a written notice together with certificate of Seller's professional registered engineer confirming that Seller's COD has been achieved; and

(f) Buyer has delivered a Commission Notice to Operate, or such other document(s) of similar effect as may be substituted therefor, which evidences no material deficiencies, in respect of the Seller's Plant Capacity and Seller's Plant operations;

and for purposes of this EPA, Seller's COD will be deemed to have occurred at 24:00 PPT on the later of the dates set out above.

1.76 "**Seller's Plant**" means Seller's plant described in Schedule "B" and all assets required to interconnect that plant to the Distribution System or Transmission System; all rights, property, facilities, assets, equipment, materials, Permits and contracts required to design, engineer, procure, construct, commission, operate and maintain the plant described in Schedule "B" and to interconnect that plant to the Distribution System or Transmission System, whether real or personal and whether tangible or intangible including all land tenure and all books, Records and accounts with respect to the Seller's Plant described in Schedule "B"; and shall include replacement parts or equipment which are of the same or similar nature as the parts or equipment being replaced and which do not materially increase the amount of Energy available from Seller's Plant.

1.77 "**Seller's Plant Capacity**" means the electrical generating capacity of the Seller's Plant set out in Schedule "B".

1.78 "**Seller's Plant Load**" means any electrical energy consumed by Seller's Plant.

1.79 "**Single Line Diagram**" means the simplified electrical representations of the Seller's Plant, the Interconnection, the Distribution System and Transmission System attached hereto in Schedule "B".

1.80 "**SOP OIC**" means that Order in Council issued by the Government of Yukon on January 24, 2019 regarding, among other things, the Standing Offer Program.

1.81 "**SOP Rules**" means the Standing Offer Program Rules developed by the Government of Yukon which governed this EPA as at the date of this EPA.

1.82 "**Standing Offer Program**" or "**SOP**" means the Standing Offer Program as described in the IPP Policy.

1.83 "**System Interconnection Guidelines**" means those system interconnection guidelines in the form attached as Schedule "G" hereto, as amended or replaced by Buyer from time to time. **[Note to Developer - where the Project is located on AEY's portion of the YIS, the EPA will be entered into between Seller and YEC, however the System Interconnection Guidelines and the Joint Operating Procedure will be established under a 3 party agreement among Seller, YEC and AEY]**

1.84 "**System Interconnection Study Report**" means the detailed interconnection study issued to Seller by Buyer which, among other things, (i) evaluates the impact of the Project on the reliability of Buyer's system, (ii) provides a planning-level estimate of the required System Upgrades and New Interconnection Facilities and associated costs, and (iii) establishes the Line Loss Methodology for this Project, a copy of which is attached as Schedule "D".

1.85 "**System Upgrades**" means additions, modifications and upgrades to the Distribution System, Transmission System or any portion of Buyer's generation system that are determined by Buyer to be required in order to facilitate the interconnection and to allow such Distribution System, Transmission System or any portion of Buyer's generation system to support the integration of the Energy produced by the Seller's Plant in accordance with this EPA and the System Interconnection Guidelines, which are identified in the System Interconnection Study Report (and as further refined in subsequent interconnection studies, if required by Buyer) and approved by Buyer, but excluding any New Interconnection Facilities.

1.86 "**System Upgrade Costs**" means all costs incurred by Buyer for the design, engineering, procurement, construction, installation and commissioning of the System Upgrades, including applicable studies required by Buyer, an estimate of which is set out in the System Interconnection Study Report.

1.87 "**Target Buyer's COD**" means the target date for achieving Buyer's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.88 "**Target Seller's COD**" means the target date for achieving Seller's COD, being the date specified for such term in Schedule "B", as may be extended pursuant to Section 3.9, if applicable.

1.89 "**Term**" has the meaning given to such term in Section 2.1.

1.90 "**Termination Payment**" has the meaning given to such term in Schedule "F".

1.91 "**Transmission System**" means the transmission, substation, protection, control and communication facilities owned and operated by Buyer, and includes all additions and modifications to those facilities and repairs or replacements of those facilities.

1.92 "**Upgrade Costs Advance**" has the meaning given to such term in Section 3.5(a).

1.93 "**Upgrade Costs Security**" has the meaning given to such term in Section 3.5(a).

1.94 "**Utilities**" means both Yukon Energy Corporation or Yukon Electrical Company, doing business as ATCO Electric Yukon, as applicable.

1.95 "**YESAA**" means the *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c 7.

1.96 "**YESAB**" means the Yukon Environmental and Socio-economic Assessment Board.

1.97 "**YUB**" means the Yukon Utilities Board and any successor thereto appointed from time to time under the *Public Utilities Act*.

2. INTERPRETATION

2.1 **Headings** - The division of this EPA into Articles, sections, Sections, paragraphs and Schedules and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

2.2 **Plurality and Gender** - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

2.3 **Governing Law** - This EPA is made under, and will be interpreted in accordance with, the Laws of the Yukon. Subject to Section 12.1, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Yukon at Whitehorse, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

2.4 **Industry Terms** - Technical or industry specific phrases or words not otherwise defined in this EPA have the well-known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

2.5 **Statutory References** - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

2.6 **Currency** - References to dollars or $ means Canadian dollars, unless otherwise stated.

2.7 **Reference Indices** - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA will be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under Section 12.1 of this EPA.

2.8 **Conversions** - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

2.9 **Additional Interpretive Rules** - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Schedules attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, Section or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively; and

(g) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, will be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

3. ADDRESSES FOR NOTICES

3.1 **Notices to Buyer** - Except as noted below, all notices addressed to Buyer will be delivered to the following address:

To: [BUYER]
_____
Whitehorse, YT
_____
Attention: Attention: Manager
Email: _____

3.2 **Notices to Seller** - All notices addressed to Seller will be delivered to the following address:

To: [SELLER]
_____
Whitehorse, YT
_____
Attention: Attention: Manager
Email: _____

SCHEDULE "B"

PROJECT DESCRIPTION

CONTRACT PARTICULARS:

1. **Condition Date:**

[Insert the date on which the Conditions Precedent must be satisfied by Seller]

2. **Conditions Precedent:**

The Conditions Precedent are as follows:

(a) *[Seller shall have received all of the Permits described below in form and substance acceptable to Seller and Buyer, acting reasonably:*

(i) *[Regulatory Agency Authorizations]*

(ii) *[Other]*

(b) *[provision of security under Section 3.5 for System Upgrade Costs and New Interconnection Facilities Costs]; and*

(c) *[others Conditions Precedent]*.

3. **Term:**

The "**Term**" of this EPA commences on the Effective Date and continues for a period of __ years following Buyer's COD.

[Note to Developers: Developers may elect a single term under an EPA of <u>up to</u> the following number of years for the applicable Eligible Clean Energy:

<u>Eligible Clean Energy</u>	**<u>Term Limit</u>**
Wind	**25 years**
Hydro	**40 years**
Geothermal	**40 years**
Biomass	**20 years**
Solar	**25 years]**

4. **Energy Price and Seasonal Adjustment:**

(a) In each billing period, Seller shall pay to Buyer, for each KWh of Delivered Energy the "**Energy Price**" calculated as follows:

[Note to Developers: For Projects connected to the YIS, the Energy Price will be calculated as follows. The first and third blanks above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = (.5 * $__/KWh * CPI$_{\text{January 1, n}}$ / CPI$_{\text{January 1, __}}$) + (.5 * $__/KWh)]

[Note to Developers: For Projects connected to the WLG, the Energy Price will be calculated as follows. The first blank above will be completed with the applicable Base Fuel Price as described in Section 4.2 of the SOP Rules. The blank in the subscript will be completed with the year in which the EPA is signed.

Energy Price$_n$ = ($__/KWh * CPI$_{\text{January 1, n}}$ / CPI$_{\text{January 1, __}}$)]

Where:

n = the year for which the relevant calculation is being conducted

CPI $_{\text{January 1, n}}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted;

(b) For each hour, the Energy Price determined above for Delivered Energy during that hour will be adjusted to an amount (expressed in $/KWh) equal to the percentage of that Energy Price applicable for that hour as set out in the table in Schedule "I".

SELLER'S PLANT

1. **Location of Control Building:**

[Insert nearest latitude and longitude]

2. **Eligible Clean Energy Type:**

[Describe Eligible Clean Energy utilized]

3. **Seller's Plant Capacity:**

[Insert Project Nameplate Capacity]

4. **Project Energy Volume:**

[Insert Project Energy Volume in KWh in any year, being the annual energy volume which is expected to be generated by the Project determined based on the maximum number of KWh which the applicable Project would generate assuming that it generated in accordance with the Seller's Plant Capacity after taking into account a reasonable capacity factor for the applicable Eligible Clean Energy type]

5. **Seller's Plant Description:**

[Insert Project description]

Please refer to Seller's single line diagram in Exhibit B-1.

Total AC Power:
Primary AC line voltage:
Total AC line current:

Total DC power:
Open-circuit DC voltage:
Operating DC voltage:
Total DC operating current:

6. **Target Seller's COD:**

[Insert]

7. **Electrical Grid:**

[Insert Yukon Integrated System (YIS) or Watson Lake Grid (WLG)].

BUYER'S SYSTEM UPGRADES

[Note to Developers – These System Upgrades will be more fully scoped in the System Interconnection Study Report]

1. **System Upgrades:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

2. **New Interconnection Facilities:**

[Description to come]

Please refer to Buyer's single line diagram in Exhibit B-2.

3. **Target Buyer's COD:**

[To come]

BREAKERS/SWITCHES AND SYNCHRONIZATION

[Note to Developers – To be developed for each Project]

EXHIBIT B-1

Seller's Single Line Diagram

[Note to Developers – To be developed for each Project]

EXHIBIT B-2

Buyer's Single Line Diagram

[Note to Developers – To be developed for each Project]

SCHEDULE "C"

FORM OF ANNUAL OPERATING PLAN

DATE: _____, 20__.

TO: _____ ("Buyer")

RE: Electricity Purchase Agreement between _____ ("Seller") and Buyer dated the ___ day of _____, 20__ (the "EPA")

The following sets out the Annual Operating Plan of Seller for the 12 months commencing on January 1, 20__ (the "**Applicable Period**").

(a) The following (from Table E-1 of Schedule "E" of the EPA) is the schedule of the expected total deliveries of Energy at the POI in each month of the Applicable Period:

	Projected Hourly Energy (KWh/h) **(A)**	**Projected Monthly Energy (KWh)** **(B)**
January		
February		
March		
April		
May		
June		
July		
August		
September		
October		
November		
December		

(b) The following is the schedule of any Planned Outages of the Seller's Plant expected by Seller for the Applicable Period:

[to come]

(c) The following is the schedule of operations and maintenance activities planned for the Seller's Plant expected by Seller for the Applicable Period:

[to come]

Dated effective as of the date set forth above.

[SELLER]

Per: _____
[Name]
[Title]

Per: _____
[Name]
[Title]

SCHEDULE "D"

SYSTEM INTERCONNECTION STUDY REPORT

SCHEDULE "E"

MONTHLY ENERGY SHORTFALL PAYMENT

Monthly Energy Shortfall Payments

In any calendar month in which there has occurred a Non-Permitted Distribution/Transmission Constraint then Buyer shall pay Seller Monthly Energy Shortfall Payment,

where:

"**Monthly Energy Shortfall Payment**" means the Monthly Constraint Shortfall multiplied by the price which is payable for Delivered Energy under Section 5.1 of the EPA; and

"**Monthly Constraint Shortfall**" (expressed in KWh) means, for each calendar month, means the aggregate of the duration of each Non-Permitted Distribution/Transmission Constraint (measured as a fraction determined as the aggregate number of minutes in such Non-Permitted Distribution/Transmission Constraint divided by 60) multiplied by the "Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy" set out in Table E-1 below for the applicable calendar month.

Table E-1

	Projected Hourly Energy (KWh/h) (A)	**Projected Monthly Energy (KWh) (B)**	**Non-Permitted Distribution/Transmission Constraint Factor (F1)**	**Non-Permitted Distribution/Transmission Constraint Hourly Deemed Energy (KWh/h) (A x F1)**
January			_%	
February			_%	
March			_%	
April			_%	
May			__%	
June			__%	
July			__%	
August			__%	
September			__%	
October			__%	
November			__%	
December			__%	

Revisions to Projected Hourly Energy and Projected Monthly Energy

Within 90 days following the end of the 2nd year after Buyer's COD, the Parties shall review and revise the values in Table E-1 above for Projected Hourly Energy and Projected Monthly Energy to reflect the average actual amount of Delivered Energy sold to Buyer in the 2 years following Buyer's COD for the applicable months.

SCHEDULE "F"

TERMINATION PAYMENT

The "**Termination Payment**" at any time shall be equal to (a) the Gross Termination Payment set out below for the Contract Year in which the termination occurred, less (b) the actual amounts paid or owing by Buyer to Seller for Delivered Energy for the Contract Year in which the termination occurred.

Table F-1

Termination Year	**Gross Termination Payment**
Year 1	
Year 2	
Year 3	
Year 4	
Year 5	
Year 6	
Year 7	
Year 8	
Year 9	
Year 10	
Year 11	
Year 12	
Year 13	
Year 14	
Year 15	
Year 16	
Year 17	
Year 18	
Year 19	
Year 20	
Year 21	
Year 22	
Year 23	
Year 24	
Year 25	

SCHEDULE "G"

SYSTEM INTERCONNECTION GUIDELINES

SCHEDULE "H"

JOINT OPERATING PROCEDURE

SCHEDULE "I"

DELIVERY TIME ADJUSTMENT TABLE

Seasonal Adjustment is subject to change.

Month	Seasonal Adjustment
January	100%
February	100%
March	100%
April	100%
May	100%
June	100%
July	100%
August	100%
September	100%
October	100%
November	100%
December	100%

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

LARGE PROJECTS

F2006 OPEN CALL FOR POWER

Notes to Bidders:

1. *The base form of EPA applies to Projects with a Plant Capacity of 10 MW and larger with the following characteristics:*

   - *Monthly Firm Energy Profile*
   - *Full output sold to BC Hydro*
   - *Seller retains Green Attributes*
   - *Seller retains all GHG obligations*
   - *Project is a BC Clean Electricity Project*
   - *Project has a direct interconnection to the Transmission System*
   - *Seller is a corporation rather than a joint venture or limited partnership.*

2. *The terms and conditions applicable to other types of generating facilities or ownership structures are set out in the Appendices to this EPA. The applicable provisions of Appendix 10, other than Part E, will be incorporated into the relevant sections of the Awarded EPA based on the information in the Seller's Tender. Part E will remain in Appendix 10.*

3. *All blanks in this Standard Form EPA will be completed based on information contained in the Seller's Tender.*

4. *The Awarded EPA will include the Project name on the title page and at the bottom of each page.*

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BC HYDRO

STANDARD FORM ELECTRICITY PURCHASE AGREEMENT

LARGE PROJECTS

THIS ELECTRICITY PURCHASE AGREEMENT ("**EPA**") is made as of •, 2006 (the "**Effective Date**")

BETWEEN:

_____ a corporation incorporated under the laws of _____ with its head office at _____
_____

("**Seller**")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, with its head office at 333 Dunsmuir Street, Vancouver, BC V6B 5R3.

("**Buyer**")

WHEREAS:

A. The Buyer issued a Call for Tenders on 8 December 2005 for the sale of electrical energy to the Buyer from independent power producers' generation plants in British Columbia with a capacity greater than .05 MW.

B. A Tender in respect of the Project was submitted in response to the CFT not later than _____, 2006.

C. The Seller desires to sell to the Buyer, and the Buyer desires to purchase from the Seller, Energy from the Seller's Plant on the terms, conditions and exceptions set forth in this EPA.

1. INTERPRETATION

1.1 Definitions - Appendix 1 sets out or references the definitions applicable to certain words and expressions used in this EPA.

1.2 Appendices - Attached to and forming part of this EPA are the following Appendices:

Appendix 1	-	Definitions
Appendix 2	-	Energy Profile
Appendix 3	-	Energy Price
Appendix 4	-	COD Certificate

Appendix 5	-	Seller's Plant Description
Appendix 6	-	Sample Form Standby Letter of Credit
Appendix 7	-	Sample Form Lender Consent Agreement
Appendix 8	-	Sample Form Development Progress Report
Appendix 9	-	Addresses for Delivery of Notices
Appendix 10	-	Special Terms and Conditions

1.3 Headings - The division of this EPA into Articles, sections, subsections, paragraphs and Appendices and the insertion of headings are for convenience of reference only and do not affect the interpretation of this EPA.

1.4 Plurality and Gender - Words in the singular include the plural and vice versa. Words importing gender include the masculine, feminine and neuter genders.

1.5 Governing Law - This EPA is made under, and will be interpreted in accordance with, the laws of the Province of British Columbia. Subject to section 20.7, any suit, action or proceeding (a "**Proceeding**") arising out of or relating to this EPA may be brought in the courts of the Province of British Columbia at Vancouver, and those courts have non-exclusive jurisdiction in respect of any Proceeding and the Parties hereby irrevocably attorn to the jurisdiction of such courts in respect of any Proceeding.

1.6 Industry Terms - Technical or industry specific phrases or words not otherwise defined in this EPA have the well known meaning given to those terms as of the date of this EPA in the industry or trade in which they are applied or used.

1.7 Statutory References - Reference to a statute means, unless otherwise stated, the statute and regulations, if any, under that statute, in force from time to time, and any statute or regulation passed and in force which has the effect of supplementing or superseding that statute or those regulations.

1.8 Currency - References to dollars or $ means Canadian dollars, unless otherwise stated.

1.9 Reference Indices - If any index, tariff or price quotation referred to in this EPA ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those then publicly available, approximates the intent and purpose of the index, tariff or quotation that has so ceased or changed. This EPA shall be amended as necessary to accommodate such replacement index, tariff or price quotation, all as determined by written agreement between the Parties, or failing agreement, by arbitration under section 20.7.

1.10 Conversions - If a value used in a calculation in this EPA must be converted to another unit of measurement for purposes of consistency or to achieve a meaningful answer, the value will be converted to that different unit for purposes of the calculation.

1.11 Additional Interpretive Rules - For the purposes of this EPA, except as otherwise expressly stated:

(a) "this EPA" means this EPA as it may from time to time be supplemented or amended and in effect, and includes the Appendices attached to this EPA;

(b) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this EPA as a whole and not to any particular section, subsection or other subdivision;

(c) the word "including" or "includes" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto;

(d) unless otherwise expressly stated in this EPA, the words "year" and "month" refer to a calendar year and a calendar month;

(e) any consent, approval or waiver contemplated by this EPA must be in writing and signed by the Party against whom its enforcement is sought, and may be given, withheld or conditioned in the unfettered discretion of the Party of whom it is requested, unless otherwise expressly stated;

(f) unless otherwise expressly stated in this EPA, all rights and remedies of either Party under this EPA are cumulative and not exclusive of any other remedies to which either Party may be lawfully entitled, and either Party may pursue any and all of its remedies concurrently, consecutively and alternatively;

(g) the provisions of Appendix 10, if any, govern over the other provisions of this EPA, and all provisions of this EPA are mutually explanatory of one another; and

(h) any notice required to be given, or other thing required to be done, under this EPA on or before a day that is not a Business Day, shall be deemed to be given or done when required hereunder if given or done on or before the next following Business Day.

2. TERM

2.1 Term - The term ("**Term**") of this EPA commences on the Effective Date and continues until the _TO#2____ anniversary of COD, subject to extension for the period specified pursuant to section 10.2, unless it is terminated earlier as authorized under this EPA.

3. REGULATORY REVIEW

3.1 Regulatory Review Termination - Either Party may terminate this EPA if, within 120 days after the Effective Date, the BCUC has not accepted the EPA for filing as an energy supply contract under section 71 of the UCA on terms and conditions that do not materially alter the price or any other material term or condition of the EPA ("**BCUC Acceptance**").

3.2 Regulatory Filing - The Buyer, on behalf of itself and the Seller, shall file the EPA with the BCUC within a reasonable time after the Effective Date.

3.3 EPA Support - The Buyer shall take all steps reasonably required to secure the BCUC Acceptance and the Seller shall provide any assistance reasonably requested by the Buyer to secure the BCUC Acceptance. The Parties will not take, and will cause their Affiliates not to take, any action inconsistent with the performance by the Parties of their obligations under this section 3.3. If a Party fails to comply with this section (the "**Breaching Party**") and, as a result, the EPA is terminated under section 3.1, the Breaching Party shall pay the non-Breaching Party, by not later than 5 Business Days

after the date of termination, an amount equal to $60,000/MW multiplied by the Plant Capacity. The Breaching Party's liability for a breach of this section 3.3 is limited to the amount set out in this section.

3.4 Termination - A Party entitled to terminate under section 3.1 must do so by giving notice to terminate to the other Party at any time after the right to terminate arises pursuant to section 3.1 and prior to the earlier of:

(a) the date of issuance of the BCUC Acceptance; and

(b) the date that is 150 days after the Effective Date.

3.5 Effect of Termination - If this EPA is terminated by either Party in accordance with sections 3.l and 3.4, the following provisions shall apply:

(a) on or before the 30th day following the date of termination, or if that day is not a Business Day, then on or before the next succeeding Business Day, the Buyer shall return the Performance Security to the Seller after deducting any amount to which the Buyer is entitled but which has not been paid pursuant to section 3.3 of this EPA; and

(b) except as set out in section 15.3, the Parties shall have no further liabilities or obligations under, or in relation to, this EPA.

4. DEVELOPMENT

4.1 Development and Construction of the Seller's Plant - The Seller shall, at its expense, perform, or cause to be performed, all Project activities necessary to complete the construction and commissioning of the Seller's Plant and achieve COD in accordance with the terms and conditions of this EPA. The Seller shall commence such Project activities by the date that is the later of: (a) 30 days after the BCUC Acceptance; or (b) if a right to terminate arises under section 3.1, 30 days after that right to terminate has expired, and shall thereafter diligently and continuously carry out such Project activities.

4.2 Modification to Plant Capacity - The Seller shall construct the Seller's Plant with a capacity that does not exceed the Plant Capacity. Except as set out in this section and notwithstanding section 6.2, the Seller shall not increase or decrease the Plant Capacity without the Buyer's prior consent. The Seller may at any time prior to the Guaranteed COD give notice to the Buyer that the Seller intends to increase or decrease the Plant Capacity by an amount not exceeding 10% of the Plant Capacity specified in Appendix 5, provided that:

(a) the Seller has completed all studies required by the Transmission Authority in connection with the proposed increase or decrease in Plant Capacity, such studies include an estimate of any increase in Network Upgrade Costs resulting from the proposed increase or decrease in the Plant Capacity, and the Seller provides copies of such studies to the Buyer together with the notice to the Buyer;

(b) the Seller shall be responsible for, and shall pay, all costs associated with the increase or decrease in the Plant Capacity, including all additional Direct Assignment Costs and Network Upgrade Costs in accordance with section 4.5;

(c) prior to the earlier of:

(i) 30 days after the date of delivery of a notice to the Buyer under this section, and

(ii) the date on which any additional Network Upgrade Costs associated with the increase or decrease in Plant Capacity are incurred,

the Seller shall deliver to the Buyer replacement Performance Security calculated in the manner set out in Appendix 1 to reflect any proposed increase or decrease in the Plant Capacity and an amount equal to the total estimated increase in Network Upgrade Costs resulting from the proposed increase or decrease in the Plant Capacity. Upon receipt of the replacement Performance Security in the required form, the Buyer shall release the existing Performance Security to the Seller, without deduction, other than prior deductions, if any, properly made hereunder;

(d) the Seller shall complete all construction and commissioning associated with the increase or decrease in the Plant Capacity prior to COD;

(e) the Guaranteed COD will not be extended by any increase or decrease in the Plant Capacity; and

(f) the Seller may give only one notice under this section.

Upon delivery by the Seller of a notice under this section and compliance by the Seller with subsections (a) and (c) above, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 5 to reflect the proposed increase or decrease in the Plant Capacity as set out in the Seller's notice. The Buyer is not required to accept or pay for any Energy associated with an increase in the Plant Capacity that does not comply with this section and section 7.5 applies to such Energy.

4.3 Permits - The Seller shall promptly obtain, comply with and maintain in full force and effect all Permits. The Seller shall on request promptly provide to the Buyer copies of all Material Permits.

4.4 Development Reports - On each January 1, April 1, July 1 and October 1 after the Effective Date, (or, where such day is not a Business Day, on the first Business Day thereafter) and continuing until COD, the Seller shall deliver to the Buyer a report in the form specified in Appendix 8, describing the progress of the Project.

4.5 Project Changes - The Seller shall not make any change to the point of interconnection with the Transmission System (including any change to the point of interconnection specified in the F2006 CFT Preliminary Interconnection Study Report) without the prior consent of the Buyer, such consent not to be unreasonably withheld, provided that the Seller acknowledges that the Buyer is entitled to require as a condition of the Buyer's consent that the Seller enter into an amendment to this EPA as required to put the Buyer in the position it would have been in under this EPA had the Seller not made a change to the point of interconnection, including with respect to the amount of Eligible Energy. If the Seller makes any change to the point of interconnection between the Seller's Plant and the Transmission System as set out in the F2006 CFT Preliminary Interconnection Study Report or any other change to the information relied on by the Transmission Authority in completing the F2006 CFT Preliminary Interconnection Study Report and developing the Network Upgrade Cost estimate for purposes of the CFT, the Seller shall be liable for all costs related directly or indirectly to such change and for all other losses, costs and damages suffered or incurred by the Buyer, whether as a transmission customer or otherwise, as a result of such change and the Seller shall pay any such amount within 30 days after receiving an invoice from the Buyer for such amount.

5. COMMERCIAL OPERATION DATE

5.1 Guaranteed COD - The Seller shall ensure that the Seller's Plant achieves COD by the Guaranteed COD plus Force Majeure Days.

5.2 Requirements for COD - Subject to sections 5.5 and 5.6, the Seller's Plant will have achieved COD at the commencement of the hour immediately following the hour in which all of the following conditions have been satisfied:

(a) the Seller has obtained all Material Permits and all such Material Permits are in full force and effect;

(b) the Seller's Plant has generated Energy over any continuous 72 hour period, in compliance with all Material Permits, and delivered such Energy to the POI in an amount not less than the greater of:

(i) 90% of the applicable Monthly Firm Energy Delivery Rate multiplied by 72; and

(ii) 20% of the Plant Capacity multiplied by 1 hour multiplied by 72;

(c) the Seller is not: (i) Bankrupt or Insolvent; (ii) in material default of any of its covenants, representations, warranties or obligations under this EPA (other than those defaults in respect of which the Seller has paid all LDs owing under this EPA); or (iii) in material default under any Material Permit, any tenure agreement for the site on which the Seller's Plant is located, the Interconnection Agreement or the Facilities Agreement; and

(d) the Seller has delivered to the Buyer:

(i) a Declaration of Compatibility-Generator (Operating), or such other document(s) of similar effect as may be substituted therefor, issued by the Transmission Authority to the Seller under the Interconnection Agreement;

(ii) data from the Metering Equipment sufficient to demonstrate compliance by the Seller with subsection 5.2(b);

(iii) payment of any amounts owing by the Seller to the Buyer under any of sections 4.2, 4.5 and 5.7; and

(iv) proof of registration by the Seller with Measurements Canada as an energy seller with respect to the Seller's Plant,

provided that, except as hereinafter provided, within 30 days after the last of the requirements set out above is satisfied the Seller delivers to the Buyer: (I) a COD Certificate; (II) the Long Term Operating Plan; and (III) the Annual Operating Plan for the period from COD to December 31 next following COD or if COD occurs after September 30, for the period from COD to December 31 in the year following COD. If the COD Certificate, Long Term Operating Plan and Annual Operating Plan are not delivered by that date, COD will occur at 12:00 PPT on the day of delivery to the Buyer of the last of the foregoing documents. For greater certainty, the Parties acknowledge that, notwithstanding satisfaction of all the conditions set out in subparagraphs (a) to (d) above, the Seller may defer delivery of the documents

described in (I), (II) and (III) above until, and the COD will not occur earlier than, the date determined under section 5.5.

5.3 Buyer Right to Observe - The Seller shall provide not less than 10 days' prior notice to the Buyer of the commencement of any proposed testing under subsection 5.2(b) and the Buyer may attend and observe each test under that subsection. If the Seller has given notice to the Buyer in accordance with this section, the Seller shall not be required to give a notice to the Buyer of any further tests which are commenced within 72 hours of the prior test under subsection 5.2(b). The Seller shall provide a new notice in accordance with this section 5.3 in respect of any test that commences more than 72 hours after the end of an unsuccessful test under subsection 5.2(b).

5.4 COD Disputes - The Buyer may, by notice to the Seller within 10 Business Days after the date of delivery to the Buyer of a COD Certificate, contest the COD Certificate on the grounds that the Seller has not satisfied the requirements for COD in section 5.2. Pending the final resolution of any dispute relating to whether the requirements for COD have been satisfied, the Seller shall not be required to remit any COD Delay LDs, provided that upon final determination of the matter, if the determination is made that COD has not been achieved, the Seller shall forthwith remit COD Delay LDs in accordance with section 12.1 calculated from the Guaranteed COD plus Force Majeure Days, together with applicable interest in accordance with subsection 9.2(b). If the Buyer does not deliver a notice to the Seller contesting the COD Certificate within the time specified in this section, COD will be deemed to have occurred as provided in section 5.2.

5.5 Early COD - Except with the Buyer's prior consent, COD may not occur earlier than the later of: (a) 1 October 2007; and (b) 365 days prior to the Guaranteed COD. The Buyer shall not be required to incur any incremental expense (other than payment for Eligible Energy) to enable COD to occur prior to the Guaranteed COD.

5.6 Deemed COD - If on or after the Guaranteed COD, the Seller's Plant has satisfied all requirements for COD, other than those requirements that depend on completion of Network Upgrades, and if the Seller cannot achieve COD solely as a result of a delay in completion of Network Upgrades and such delay is solely caused by the Buyer, then COD will be deemed to have occurred on or after the Guaranteed COD at the commencement of the hour following the hour in which all other conditions for COD were satisfied. The Buyer shall thereafter be liable to pay the Seller for that portion of the Monthly Firm Energy Amount that could have been generated and delivered at the POI but for the delay in completion of the Network Upgrades described above, and all such Energy will be considered Eligible Energy for purposes of this EPA. The portion of the Monthly Firm Energy Amount that could have been generated and delivered at the POI will be determined based on the information described in section 7.9. Except for the payments for deemed Eligible Energy provided for pursuant to this section, the Seller shall have no other rights or remedies against the Buyer, and the Buyer shall have no other liability, with respect to any delay in completion of the Network Upgrades. If the Seller's Plant fails to satisfy the requirements specified in section 5.2 within a reasonable period, but not later than 60 days after completion of the Network Upgrades, the Seller will be deemed not to have achieved COD and the Seller shall within 10 days after receipt of an invoice from the Buyer, refund to the Buyer all payments made by the Buyer to the Seller prior to that date. This section 5.6 will not apply if a delay in completion of any Network Upgrades is due, in whole or in part, to any increase or decrease in Plant Capacity from the Plant Capacity specified in Appendix 5 or to any increase in any Monthly Firm Energy Amount pursuant to section 7.2 or to any change described in section 4.5.

5.7 Early Network Upgrades - If the Seller requires Network Upgrades to be completed prior to 90 days prior to the Guaranteed COD to enable early COD or to enable sales of Pre-COD Energy to third

parties, the Seller shall give notice of such requirement to the Buyer and following delivery of such notice, the Seller and the Buyer shall discuss such requirement with the Transmission Authority to determine the incremental costs, if any, required to complete the Network Upgrades prior to 90 days prior to the Guaranteed COD. The Seller shall be responsible for and shall indemnify the Buyer from and against all such incremental costs and expenses and, prior to commencement by the Transmission Authority of any work required to advance the completion date for the Network Upgrades, shall provide to the Buyer replacement Performance Security which includes an amount equal to the total estimated increase in Network Upgrade Costs resulting from any request by the Seller to complete the Network Upgrades prior to 90 days prior to the Guaranteed COD.

6. OPERATION OF SELLER'S PLANT

6.1 Owner and Operator - The Seller shall own the Seller's Plant and shall ensure that the Seller's Plant is operated using qualified and experienced individuals.

6.2 Modifications to Seller's Plant/Additional Generators

(a) **Modifications to Seller's Plant** - The Seller shall not make, without the Buyer's prior consent, any modification or addition, or series of modifications or additions, to the Seller's Plant, except for those modifications or additions which: (i) are not likely to have an adverse effect on the Seller's ability to observe and perform its obligations under this EPA, including the Seller's obligations under subsection 6.3(f); or (ii) are required to comply with a change in Law or a change in Permit conditions (where such change in Permit conditions is initiated by a Governmental Authority) after the Effective Date. The Seller shall provide prior notice to the Buyer of any modifications or additions, or series of modifications or additions, to the Seller's Plant together with an explanation of the reason for such modifications or additions.

(b) **Additional Generators** - The Seller shall not add any additional generators on the site of the Seller's Plant or that otherwise inject output at the same POI as the Seller's Plant, unless the Seller has first entered into an amendment to this EPA with the Buyer as required to address any adverse impacts on the Buyer or on the benefit to the Buyer of this EPA resulting from the construction or operation of such additional generators.

6.3 Standard of Construction and Operation - The Seller shall cause the Seller's Plant to be designed, engineered, constructed, interconnected to the Transmission System, commissioned, operated and maintained in compliance with: (a) all applicable Laws; (b) the terms and conditions of all Permits and land tenure agreements issued in connection with the Seller's Plant; (c) Good Utility Practice; (d) the specifications in Appendix 5, as changed from time to time with the prior consent of the Buyer, provided that, subject to section 6.2, the Seller may amend the information in sections 4 and 5 of Appendix 5 at any time without consent on notice to the Buyer not less than 30 days prior to such change and the Buyer and the Seller will enter into an amendment to this EPA to amend Appendix 5 in accordance with such notice; (e) the Code of Conduct Guidelines Applicable to BC Hydro Contracts in effect as of the date specified for submission of Tenders under the CFT; (f) if applicable, the information provided to the British Columbia Minister of Energy, Mines and Petroleum Resources or to TerraChoice Environmental Marketing to obtain confirmation that the output from the Seller's Plant could be considered BC Clean Electricity in the CFT process; and (g) the terms and conditions of this EPA, the Interconnection Agreement and the Facilities Agreement. Without limiting the foregoing, all equipment installed in the Seller's Plant shall conform to the codes, standards and rules applicable to power plants in British Columbia and the Seller shall ensure that the Seller's Plant is designed, engineered and constructed to

operate in accordance with the requirements of this EPA for the full Term of this EPA. Without limiting section 7.3 but subject to subsection 7.8(a), when the Seller is delivering Energy to the Buyer, the Seller shall make commercially reasonable efforts to operate the Seller's Plant in a manner that ensures delivery of Energy at the POI at a uniform rate within each hour.

6.4 Planned Outages - The Seller shall: (a) ensure that no Planned Outage occurs during the Peak Demand Months without the Buyer's prior consent, such consent not to be unreasonably withheld, delayed or conditioned; (b) give the Buyer not less than 90 days' prior notice of any Planned Outage and such notice shall state the start date and hour and the end date and hour for the Planned Outage; (c) make commercially reasonable efforts to coordinate all Planned Outages with the Buyer's requirements as notified to the Seller; and (d) make best efforts to coordinate Planned Outages with the Transmission Authority's maintenance schedule where such schedule is publicly available or otherwise notified to the Seller. Within 45 days after the date of receipt of the Annual Operating Plan or within 14 days after receipt of any adjustment to the Annual Operating Plan pursuant to subsection 6.6(b), the Buyer may request the Seller to reschedule any Planned Outage. Within 14 days after receipt of such a request, the Seller shall provide the Buyer with an estimate, together with reasonable supporting detail, of the costs the Seller expects to incur, acting reasonably, as a result of rescheduling the Planned Outage in accordance with the Buyer's request. Within 7 days after receipt of such cost estimate, the Buyer shall notify the Seller if the Buyer requires the Seller to reschedule the Planned Outage and upon receipt of such notice from the Buyer, the Seller shall adjust the schedule for the Planned Outage as required by the Buyer, provided that the rescheduling is consistent with Good Utility Practice and does not have a materially adverse effect on the operation of the Seller's Plant or on any facility that is a thermal host for the Seller's Plant. The Buyer shall reimburse the Seller for all costs reasonably incurred by the Seller as a result of such rescheduling, but not exceeding the estimate delivered by the Seller to the Buyer under this section. For payment and all other purposes of this EPA, all Planned Outages will be deemed to start at the beginning of an hour and to end at the end of an hour.

6.5 Records - During the Term the Seller shall prepare and maintain all records required to properly administer this EPA, including Energy generation records and operating logs, a log book of all Outages and other reductions in Energy output (specifying the date, time, duration and reasons for each Outage and each reduction in Energy output), meter readings, maintenance reports, invoice support records, documents concerning compliance with Permits and applicable Laws, and all other records and logs consistent with Good Utility Practice. The Seller shall maintain such records or duplicates of such records at the Seller's Plant, or following the expiry of the Term or the earlier termination of this EPA, at such other location as may be agreed to by the Buyer, acting reasonably, for a period of not less than 7 years from the date on which each such record is created.

6.6 Reports to the Buyer - The Seller shall deliver the following documents, reports, plans and notices to the Buyer:

(a) **Long Term Operating Plan** - By the date specified in section 5.2, the Seller shall provide to the Buyer an operating plan for the Seller's Plant for a 10 year period commencing at COD and ending on December 31 of the year in which the tenth anniversary of COD occurs, including the long term major maintenance schedule. On or before September 30 in each year during the Term after the year in which COD occurs, the Seller shall provide the Buyer with an updated plan for the 10 year period commencing on the next succeeding January 1 or to the end of the Term, whichever is less. The Seller shall promptly provide the Buyer with copies of any amendments or modifications to the Long Term Operating Plan. The Long Term Operating Plan shall be

consistent with Good Utility Practice and is intended to assist the Buyer in planning activities and is not a guarantee of the timing of Planned Outages;

(b) **Annual Operating Plan** - On or before September 30 in each year during the Term, the Seller shall provide to the Buyer an operating plan for the Seller's Plant for the 12 month period commencing on the next succeeding January 1 which plan may be included in the Long Term Operating Plan. The plan shall include a schedule of Planned Outages for that 12 month period which shall comply with the provisions of section 6.4 and be consistent with Good Utility Practice. The Seller may, on not less than 90 days prior notice to the Buyer, amend the Annual Operating Plan, subject to the provisions of section 6.4;

(c) **Notice of Outages** - Other than for a Planned Outage for which notice has been given pursuant to section 6.4, the Seller shall promptly notify the Buyer of any Outage, or any anticipated Outage, of the Seller's Plant. Any notice under this subsection shall include a statement of the cause of the Outage, the proposed corrective action and the Seller's estimate of the expected duration of the Outage. The Seller shall, except with the Buyer's consent, such consent not to be unreasonably withheld, use best efforts to promptly remove or mitigate any Forced Outage. The Seller shall deliver to the Buyer concurrently with delivery of the statement described in subsection 9.1(a), a report of all Outages during the month for which the statement described in subsection 9.1(a) is issued, including a statement of the cause of each Outage;

(d) **Interconnection Agreement and Facilities Agreement Defaults** - The Seller shall give promptly to the Buyer a copy of any notice of a breach of, or default under, the Interconnection Agreement or the Facilities Agreement, whether given or received by the Seller;

(e) **Notice of Buyer Termination Event** - The Seller shall notify the Buyer promptly of any Buyer Termination Event or any material risk that a Buyer Termination Event will occur or any default by the Seller under any agreement with a Facility Lender; and

(f) **Energy Schedules** - After COD the Seller shall either (as elected by the Seller in a notice delivered to the Buyer prior to COD):

(i) on each Thursday by 12:00 PPT, deliver to the Buyer a schedule of the expected deliveries of Eligible Energy in each day during the next succeeding week commencing at 00:00 PPT on Monday; or

(ii) by 12:00 PPT on each day deliver to the Buyer a schedule of expected deliveries of Eligible Energy for the next succeeding 24 hour period commencing at 00:00 PPT,

provided that such schedules are provided for planning purposes only and do not constitute a guarantee by the Seller that Energy will be delivered in accordance with the schedules and do not limit the amount of Energy the Seller may deliver during the periods covered by the schedules. The Seller shall deliver a revised schedule to the Buyer forthwith upon becoming aware of any expected material change in a filed Energy schedule. The Seller may change its election with respect to the delivery of Energy schedules in accordance with subsection (i) or (ii) above at any time on 60 days' prior notice to the Buyer.

6.7 Exemption from Utility Regulation - The Seller shall not take any action that would cause the Seller to cease to be exempt, or omit to take any action necessary for the Seller to continue to be exempt, from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a "public utility" could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

6.8 Compliance with Emissions Requirements

(a) **GHG Requirements** - Without limiting section 4.3 or section 6.3, the Seller shall comply with all applicable Laws and all Permits regulating GHG emissions from the Seller's Plant. The Seller shall by each January 31 after COD (or, if alternate reporting dates are established under any Laws or Permits regulating GHG emissions from the Seller's Plant, then by such alternate reporting dates) deliver to the Buyer a report signed by a senior officer of the Seller, in a form satisfactory to the Buyer acting reasonably, detailing the status of compliance by the Seller with this section during the immediately preceding year (or if an alternate compliance period is established under any Laws or Permits regulating GHG emissions from the Seller's Plant, then the report shall address such alternate compliance period). If the Seller is not in compliance with any Law or Permit regulating GHG emissions from the Seller's Plant and the Seller fails to remedy such non-compliance within 30 days after the date of notice from the Buyer to the Seller, the Buyer may, but is not required to, on behalf of the Seller, purchase any Compliance Units required to remedy, in whole or in part, the Seller's non-compliance with the applicable Law or Permit. The Seller shall cooperate with the Buyer as necessary to enable the Buyer to purchase such Compliance Units. The Seller shall reimburse the Buyer for all costs (including all commissions, charges, brokerage, consulting and legal fees, taxes, duties, transfer and registration fees and all other transaction costs and expenses) incurred by the Buyer in purchasing such Compliance Units, together with an administration fee equal to 15% of such costs within 30 days after receipt of an invoice from the Buyer for such amount.

(b) **Other Emissions** - Without limiting subsection (a), the Seller is solely responsible at the Seller's cost for compliance with all applicable Laws and Permits regulating all emissions from the Seller's Plant, including GHG emissions. The Buyer has no responsibility or liability of any kind whatsoever with respect to any such emissions.

6.9 Disclosure of Information by Transmission Authority - The Seller consents to the Transmission Authority disclosing to the Buyer on request:

(a) all information with respect to Network Upgrades, including any information provided by the Seller to the Transmission Authority that relates to, or affects, Network Upgrades including any preliminary interconnection application, study and report, and any subsequent applications, studies and reports, that contain information relevant to Network Upgrades;

(b) all metering data collected by, or provided to, the Transmission Authority with respect to the Seller's Plant;

(c) copies of any notice of a breach of, or default under, the Interconnection Agreement or the Facilities Agreement given or received by the Transmission Authority; and

(d) any other information provided by the Seller to the Transmission Authority or by the Transmission Authority to the Seller that is relevant to the administration of this EPA.

The Seller shall promptly on request by the Buyer provide to the Buyer written confirmation of the foregoing consents for delivery by the Buyer to the Transmission Authority.

6.10 Islanding - Subject to the provisions of this section, at any time after the Effective Date and prior to completion by the Seller of the final engineering design for the Seller's Plant, the Seller shall, at the request of the Buyer, provide all information and cooperation required to enable the Buyer to undertake, at the Buyer's cost, any studies the Buyer considers necessary to determine the ability of the Seller's Plant to provide Planned Islanding Capability and the estimated cost of providing, operating and maintaining such Planned Islanding Capability. The Seller shall provide the Buyer with not less than 120 days prior notice of the anticipated date of completion of the final engineering design for the Seller's Plant and the Buyer shall advise the Seller within 60 days after receipt of such notice if the Buyer intends to undertake any studies pursuant to this section. The Buyer shall, within 30 days after receipt of an invoice together with reasonable supporting information, reimburse the Seller for all reasonable costs incurred by the Seller, that the Seller would not otherwise have incurred, to provide the Buyer with information required for any studies pursuant to this section. The Buyer may on notice to the Seller within 30 days after receipt of all studies commissioned by the Buyer under this section advise the Seller that the Buyer wishes to enter into negotiations with the Seller with respect to the Seller's Plant providing Planned Islanding Capability, including any amendments required to this EPA as a result thereof. Upon receipt of such notice the Parties shall negotiate in good faith to determine the terms and conditions on which the Seller will provide such Planned Islanding Capability.

6.11 BC Clean Electricity - If in the CFT process the output from the Seller's Plant was treated as BC Clean Electricity based on a letter from TerraChoice Environmental Marketing confirming eligibility of the Seller's Plant for EcoLogo^{M} Certification, and if the Seller does not obtain EcoLogo^{M} Certification by the date that is one year after COD, the Seller shall within 60 days after the first anniversary of COD, provide a letter to the Buyer from the British Columbia Minister of Energy, Mines and Petroleum Resources confirming that the output from the Seller's Plant is BC Clean Electricity together with a copy of all information provided to the Minister to obtain such confirmation. Without limiting section 6.5, the Seller shall maintain, and shall within 10 Business Days after a request from the Buyer, provide to the Buyer all information the Buyer requires to verify qualification of the output from the Seller's Plant as BC Clean Electricity. The Buyer may at any time during the Term conduct or have a third Person with the necessary expertise conduct, at the Buyer's expense, an audit of the Project Assets, its employees and relevant documentation to verify qualification of the output from the Seller's Plant as BC Clean Electricity. The Seller shall promptly provide to the Buyer any consents required to enable the Buyer to make enquiries with any Governmental Authorities concerning the qualification of the output from the Seller's Plant as BC Clean Electricity. The Seller consents to the disclosure by the Buyer to any Person or any Governmental Authority of any Confidential Information with respect to the Seller's Plant that the Buyer is required to disclose to verify qualification of the output of the Seller's Plant as BC Clean Electricity or to provide confirmation to any such Person or Governmental Authority that the output from the Seller's Plant qualifies as BC Clean Electricity.

7. PURCHASE AND SALE OBLIGATIONS

7.1 Pre-COD Energy - The Buyer shall make commercially reasonable efforts to accept delivery at the POI of all Pre-COD Energy, provided that the Buyer shall not be required to take any steps or to incur any incremental expense to enable the delivery of Pre-COD Energy to the POI prior to 90 days before the Guaranteed COD. Prior to the earlier of COD and the Guaranteed COD the Seller may, on prior notice to

the Buyer, sell any Energy to any Person other than the Buyer, and in that case such Energy shall not be delivered, or be deemed to be delivered, to the Buyer.

7.2 Modification to Monthly Firm Energy Amount - The Seller may at any time prior to the first anniversary of COD, give notice to the Buyer that the Seller elects to increase or decrease the Monthly Firm Energy Amount for one or more months, to take effect on the first day of the month immediately following the giving of such notice, provided that the net change in the annual total of the Monthly Firm Energy Amounts resulting from such increase or decrease in the Monthly Firm Energy Amounts does not exceed 10%. Upon receipt of such notice, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 2 in accordance with the Seller's notice, provided that:

(a) any such increase or decrease in the Monthly Firm Energy Amounts does not result in the total of the Monthly Firm Energy Amounts for the period from April to July, inclusive, exceeding one-third of the annual total of the Monthly Firm Energy Amounts;

(b) any such increase or decrease in the Monthly Firm Energy Amounts does not result in the Monthly Firm Energy Amount for any month exceeding the Plant Capacity multiplied by the number of hours in the applicable month;

(c) the provisions of subsections 4.2(a) and (b) apply to any such increase or decrease in the Monthly Firm Energy Amounts, *mutatis mutandis*; and

(d) the Seller may give only one notice under this section.

7.3 Post-COD Sale of Energy - Subject to subsection 7.8(a), in each month during the Term after COD, the Seller shall sell and deliver to the Buyer at the POI the Monthly Firm Energy Amount for the applicable month, provided that if COD occurs on any day other than the first day of the month, the Monthly Firm Energy Amount for the month in which COD occurs and for the last month of the Term will be reduced to reflect in the former case, the number of days in the month after COD, and in the latter case, the number of days prior to the expiry of the Term.

7.4 Post-COD Purchase of Energy - Subject to subsection 7.8(b), in each month during the Term after COD, the Buyer shall purchase, and accept delivery from the Seller at the POI of, all Eligible Energy.

7.5 Exclusivity - The Seller shall not at any time during the Term commit, sell or deliver any Energy to any Person, other than the Buyer under this EPA, except for:

(a) Pre-COD Energy sold to third parties in accordance with section 7.1;

(b) during any period in which the Buyer is in breach of its obligations under section 7.4; and

(c) during any period in which the Buyer is not accepting deliveries of Energy from the Seller due to Force Majeure invoked by the Buyer.

7.6 Custody, Control and Risk of Energy - Custody, control, risk of, and title to all Pre-COD Energy delivered to the Buyer and all Eligible Energy passes from the Seller to the Buyer at the POI. The Seller shall ensure that all Energy delivered to the Buyer under this EPA is free and clear of all liens, claims, charges and encumbrances. The Seller shall be responsible for all transmission losses and costs, if any, relating to the transmission of Energy from the Seller's Plant to the POI.

7.7 Price and Payment Obligation - The Buyer shall pay for all Test Energy in respect of which the Seller has not given a notice under section 7.1 and all Eligible Energy in accordance with Appendix 3.

7.8 Limitations on Delivery and Acceptance Obligations

(a) **Limitations on Delivery Obligations** - The obligations of the Seller under section 7.3 are subject to:

(i) Force Majeure invoked by the Seller in accordance with Article 11;

(ii) any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI for reasons that are not attributable to the Seller or the Seller's Plant;

(iii) disconnection of the Seller's Plant from the Transmission System by the Transmission Authority for reasons that are not attributable to the Seller or the Seller's Plant;

(iv) the right of the Seller to suspend its performance under this EPA in accordance with Article 14; and

(v) Authorized Planned Outages.

(b) **Limitations on Acceptance Obligations** - The obligations of the Buyer under sections 7.1 and 7.4 are subject to:

(i) Force Majeure invoked by the Buyer in accordance with Article 11;

(ii) disconnection of the Seller's Plant from the Transmission System for reasons not attributable to the Buyer;

(iii) any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI for reasons not attributable to the Buyer; and

(iv) the right of the Buyer to suspend the Seller's performance under the EPA in accordance with Article 14.

7.9 Deemed Deliveries - If in any month after COD the Seller is unable to deliver Energy at the POI at any time during that month solely as a result of:

(a) any disconnection of the Seller's Plant from the Transmission System or any Outage, suspension, constraint or curtailment in the operation of the Transmission System preventing or limiting physical deliveries of Eligible Energy at the POI where:

(i) the Transmission Authority is authorized to disconnect the Seller's Plant or suspend firm transmission service under the Interconnection Agreement, Facilities Agreement, any tariff applicable to firm transmission or interconnection service or any other legally enforceable right; and

(ii) such disconnections, Outages, suspensions, constraints or curtailments exceed in the aggregate 24 hours, whether or not continuous, in that month,

but excluding any disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant; or

(b) a breach by the Buyer of its obligations under section 7.4,

then, notwithstanding that the Buyer is excused under subsection 7.8(b) from its obligations under section 7.4, in the case of an event described in subsection 7.9(a), all or that portion of the applicable Monthly Firm Energy Amount that could have been generated and delivered at the POI in each hour after the 24 hours has elapsed, but for the occurrence of the event described in subsection 7.9(a) will be deemed to be Eligible Energy, and in the case of an event described in subsection 7.9(b), the amount of Energy, not exceeding the Plant Capacity, that could have been generated and delivered at the POI but for the occurrence of the event described in subsection 7.9(b) will be deemed to be Eligible Energy. The amount of Energy that could have been generated and delivered at the POI during an event described in subsection 7.9(a) or (b) will be determined based on the Seller's Energy schedule for the applicable period, meter readings with respect to the Energy Source, if applicable, readings of the Metering Equipment before and after the occurrence of the event described in subsection 7.9(a) or (b) and other available information. There will be no deemed Eligible Energy during any period specified as a Planned Outage in a notice delivered by the Seller under section 6.4. For greater certainty, the provisions of this section 7.9 will not apply during any period when either Party is excused, in accordance with Article 11, from its obligation to deliver, or to accept delivery of, Energy as a result of a Force Majeure.

7.10 Green Attributes - The Buyer acknowledges that the Seller retains title and all right, benefit and interest in, to and arising from the Green Attributes.

8. METERING

8.1 Installation of Metering Equipment - The Seller shall, at its cost, ensure that revenue metering equipment (the "**Metering Equipment**") is installed, operated and maintained in accordance with the requirements of the Transmission Authority and the requirements of this section. The Seller shall ensure that the Seller's Plant is equipped with electronic meters and SCADA capability. The Metering Equipment shall be installed at a location approved by the Buyer, acting reasonably, which location shall be such that the Metering Equipment can measure the Energy generated by the Seller's Plant independent of all other generation equipment or facilities. The Seller shall ensure that the Metering Equipment is: (a) capable of being remotely interrogated; (b) sufficient to accurately meter the quantity of Energy to be purchased and sold hereunder; (c) calibrated to measure the quantity of Energy delivered to the POI, after adjusting for any line losses from the Seller's Plant to the POI; and (d) in compliance with all requirements set out in the *Electricity and Gas Inspection Act* (Canada) and associated regulations.

8.2 Operation of Metering Equipment - The Metering Equipment shall be used for purposes of calculating the amount of Eligible Energy. In the event of any failure of the Metering Equipment, the Parties shall, until such time as the Metering Equipment has been repaired or replaced, rely upon information provided by any back-up meter installed pursuant to section 8.3, or, in the absence of such back-up meter, the Seller's metering equipment, if any, for purposes of calculating payments due under this EPA. If there is any dispute regarding the accuracy of the Metering Equipment, either Party may give notice to the other Party of the dispute, in which case the Buyer and the Seller will proceed to rectify the matter in accordance with the *Electricity and Gas Inspection Act* (Canada). The Seller shall allow the Buyer to access the Seller's Plant at any time during normal business hours on reasonable advance notice

for purposes of inspecting the Metering Equipment. The Seller shall, on the Buyer's request, cause the Metering Equipment to be inspected, tested and adjusted provided that, except as set out below, the Buyer shall not make such a request more than once in each year during the Term. The Seller shall give the Buyer reasonable prior notice of all inspections, tests and calibrations of the Metering Equipment and shall permit a representative of the Buyer to witness and verify such inspections, tests and calibration. If either Party has reason to believe that the Metering Equipment is inaccurate, the Seller shall cause the Metering Equipment to be tested forthwith upon becoming aware of the potential inaccuracy. The Seller shall provide the Buyer with copies of all meter calibration test results and all other results of any test of the Metering Equipment. If any test of the Metering Equipment discloses an inaccuracy outside the inaccuracies permitted under the *Electricity and Gas Inspection Act* (Canada), any payments or adjustments made or calculated under this EPA that would have been affected by the inaccuracy shall be recalculated to correct for the inaccuracy. For purposes of such correction, if the inaccuracy is traceable to a specific event or occurrence at a reasonably ascertainable time, then the adjustment shall extend back to that time; otherwise, it shall be assumed that the error has existed for a period equal to one half of the time elapsed since COD or one half of the time since the last meter test, whichever is more recent, but in any event shall not extend back more than 36 months. Any amounts which are determined to be payable or subject to refund as a result of such re-computations shall be paid to the Party entitled to such amounts within 20 days after the paying Party is notified of the re-computation.

8.3 Duplicate Metering Equipment - The Buyer may at any time during the Term at the Buyer's sole cost, on not less than 30 days prior notice to the Seller, install a duplicate revenue meter at the Seller's Plant at a location to be agreed upon by the Buyer and the Seller, acting reasonably, and the Seller shall allow the Buyer to access the Seller's Plant for such purpose and for the purpose of inspecting and maintaining such equipment. The Seller shall make transformers, transformer connections and telephone access available to the Buyer, as required, if the Buyer elects to install a duplicate revenue meter. Any duplicate revenue meter and metering equipment installed by the Buyer will remain the property of the Buyer, and the Seller shall not tamper with, remove or move such meter or equipment.

8.4 Energy Source Meters - The Seller shall, at its cost, ensure that meters are installed at the Seller's Plant capable of measuring the Energy Source available to the Seller's Plant.

9. STATEMENTS AND PAYMENT

9.1 Statements

(a) In each month after the month in which Pre-COD Energy is first delivered to the Buyer, the Seller shall, by the 15th day of the month or the first Business Day thereafter, deliver to the Buyer a statement prepared by the Seller for the preceding month. The statement must comply with any billing guideline issued by the Buyer pursuant to section 9.4 and must indicate, among other things, the amount of Eligible Energy, the price payable for the Eligible Energy, any LDs payable by the Seller to the Buyer and any Final Amounts owing by either Party to the other Party and set out in reasonable detail the manner by which the statement and the amounts shown thereon were computed. To the extent not previously delivered pursuant to the requirements of this EPA, the statement must be accompanied by sufficient data to enable the Buyer, acting reasonably, to satisfy itself as to the accuracy of the statement.

(b) Either Party may give notice to the other Party of an error, omission or disputed amount on a statement within 36 months after the statement was first issued together with reasonable detail to support its claim. After expiry of that 36 month period, except in the

case of wilful misstatement or concealment, amounts on a previously issued statement will be considered accurate and amounts which were omitted will be considered to be nil, other than amounts disputed in accordance with this subsection within the 36 month period, which will be resolved in accordance with this EPA.

9.2 Payment

(a) Within 30 days after receipt of a statement delivered pursuant to subsection 9.1(a) and subject to sections 9.5 and 13.6, the Buyer shall pay to the Seller the amount set out in the statement, except to the extent the Buyer in good faith disputes all or part of the statement by notice to the Seller in compliance with subsection 9.1(b). If the Buyer disputes any portion of a statement, the Buyer must nevertheless pay the undisputed net amount payable by the Buyer pursuant to the statement.

(b) Any amount required to be paid in accordance with this EPA, but not paid by either Party when due, will accrue interest at an annual rate equal to the Prime Rate plus 3%, compounded monthly. Any disputed amount that is found to be payable will be deemed to have been due within 30 days after the date of receipt of the statement which included or should have included the disputed amount.

9.3 Taxes - All dollar amounts in this EPA do not include any value added, consumption, commodity or similar taxes applicable to the purchase by the Buyer of the Eligible Energy, including GST and PST, which, if applicable, will be borne by the Buyer and added to each statement.

9.4 Billing Guideline - The Seller shall comply with any reasonable written billing guideline (including any requirements with respect to the form of statements pursuant to section 9.1) issued by the Buyer during the Term, provided that any such billing guideline shall not vary the express terms of this EPA. If there is any conflict between a billing guideline and this EPA, this EPA will govern.

9.5 Set-off - If the Buyer and the Seller each owe the other an amount under this EPA in the same month, then such amounts with respect to each Party shall be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount shall pay to the other Party the difference between the amounts owed, provided that:

(a) this section 9.5 applies only to any purchase price for Eligible Energy owing by the Buyer to the Seller, any LDs owing by the Seller to the Buyer, any Termination Payment or Final Amount owing by either Party to the other Party and any amount owing by the Seller to the Buyer under section 6.8; and

(b) no LD, Termination Payment, Final Amount or amount owing by the Seller to the Buyer under section 6.8 shall be added to or deducted from the price owing by the Buyer to the Seller for Eligible Energy unless the LD, Termination Payment, Final Amount or amount owing under section 6.8 remains unpaid 30 days after the Party owed the LD, Termination Payment, Final Amount or amount owing under section 6.8 gives notice to the other Party.

Except as otherwise expressly provided herein, each Party reserves all rights, counterclaims and other remedies and defences which such Party has or may be entitled to arising from or related to this EPA.

10. INSURANCE/DAMAGE AND DESTRUCTION

10.1 Insurance - The Seller shall, by the date specified in section 4.1 for the commencement of the Project activities necessary to construct the Seller's Plant, obtain, maintain and pay for: (a) policies of commercial general liability insurance with a per occurrence limit of liability not less than $_____ applicable to the Project separate from all other projects and operations of the Seller; and (b) property insurance and Construction Insurance with limits of liability and deductibles consistent with those a prudent owner of a facility similar to the Seller's Plant would maintain and those the Facility Lender requires. All commercial general liability policies must include the Buyer, its directors, officers, employees and agents as additional insureds and must contain a cross liability and severability of interest clause. All policies of insurance must be placed with insurers that have a minimum rating of A- (or equivalent) by A.M. Best Company and are licensed to transact business in the Province of British Columbia and must be endorsed to provide to the Buyer 30 days prior written notice of cancellation, non-renewal or any material amendment that results in a reduction in coverage. The Seller shall give the Buyer a copy of the insurance certificate(s) for the insurance required to be maintained by the Seller under this section not more than 30 days after the effective date of coverage and immediately upon renewal thereafter. The Seller shall be responsible for the full amount of all deductibles under all insurance policies required to be maintained by the Seller under this section.

[Note to Bidders: The insurance policy limit of liability set out in section 10.1 of the Awarded EPA will be based on the Plant Capacity as follows:

Greater than 10 MW to 25 MW	***-***	***$ 3,000,000***
Greater than 25 MW to 50 MW	***-***	***$ 5,000,000***
Greater than 50 MW to 100 MW	***-***	***$10,000,000***
Greater than 100 MW	***-***	***$20,000,000]***

10.2 Damage or Destruction of the Seller's Plant

(a) **Major Damage** - If the Seller's Plant suffers Major Damage caused by a Force Majeure event in respect of which the Seller has invoked Force Majeure in accordance with Article 11, then the Seller may at its option exercisable by notice to the Buyer within 120 days after the occurrence thereof, either: (i) proceed to diligently and expeditiously and at its own cost repair the Major Damage and restore the Seller's Plant to at least the condition in which it was in immediately prior to the Major Damage and resume deliveries of Energy hereunder; or (ii) terminate this EPA, and in that event, the provisions of section 15.3 and subsection 15.5(c) apply. If the Seller fails to give notice exercising its option within such 120 day period, it will be deemed to have exercised the option described in (i) above. Nothing in this section limits the rights of either Party to terminate this EPA under any other section of this EPA.

(b) **Non-Major Damage** - If the Seller's Plant is damaged or destroyed, in whole or in part, by any cause or peril, then, except in the case of Major Damage caused by a Force Majeure event in respect of which the Seller has invoked Force Majeure in accordance with Article 11, the Seller shall within 30 days after the date of the damage or destruction provide notice to the Buyer setting out the date by which the Seller, acting reasonably, can resume delivering Energy to the Buyer which date shall be not more than 365 days after

the date of occurrence of the damage or destruction. The Seller shall diligently and expeditiously, and at its own cost, repair the Seller's Plant and restore the same to at least the condition in which it was in immediately prior to the damage or destruction and shall complete such work not later than the date specified in the notice delivered by the Seller to the Buyer under this section. Nothing in this section limits the rights of either Party to terminate this EPA under any other section of this EPA.

(c) **Extension of Term** - Provided the Seller complies with its obligations under this section 10.2, the Term shall be extended by the number of days from the date of the event of damage or destruction to the date on which the Seller resumes delivering Energy to the Buyer.

11. FORCE MAJEURE

11.1 Invoking Force Majeure and Notice

(a) Neither Party will be in breach or default as to any obligation under this EPA if that Party is unable to perform that obligation due to an event or circumstance of Force Majeure, of which notice is given as required in this section 11.1 and, subject to any limitations expressly set out in this EPA, the time for performance of such obligation will be extended by the number of days that Party is unable to perform such obligation as a result of the event or circumstance of Force Majeure.

(b) If there is a Force Majeure preventing a Party from performing an obligation under this EPA, that Party shall promptly notify the other Party of the Force Majeure. The notice must identify the nature of the Force Majeure, its expected duration and the particular obligations affected by the Force Majeure. The affected Party shall provide reports to the other Party with respect to the Force Majeure at such intervals as the other Party may reasonably request while the Force Majeure continues. A Party will be deemed to have invoked Force Majeure from the date when that Party gives notice of the Force Majeure in accordance with this subsection 11.1(b), provided that if such notice is given within 24 hours after the later of: (i) the occurrence of the Force Majeure; and (ii) the time when the Party knew, or reasonably ought to have known, of the occurrence of the Force Majeure, the Party will be deemed to have invoked Force Majeure from the date on which the event of Force Majeure occurred. The Party invoking Force Majeure shall promptly respond to any inquiry from the other Party regarding the efforts being undertaken to remove the Force Majeure. The Party invoking Force Majeure shall give prompt notice of the end of the Force Majeure.

11.2 Exclusions - A Party may not invoke Force Majeure:

(a) for any economic hardship, or for lack of money, credit or markets; or

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a Permit or of any applicable Laws; or

(c) for a mechanical breakdown, unless the Party seeking to invoke Force Majeure can demonstrate by clear and convincing evidence that the mechanical breakdown was caused by a latent defect in the design or manufacture of the equipment which could not reasonably have been identified by normal inspection or testing of the equipment; or

(d) if the Force Majeure was caused by a breach of, or default under, this EPA or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure; or

(e) for any acts or omissions of third parties, including any Affiliate of the Seller, or any vendor, supplier, contractor or customer of a Party, but excluding Governmental Authorities, unless such acts or omissions are themselves excused by reason of Force Majeure as defined in this EPA; or

(f) for any disconnection of the Seller's Plant from the Transmission System, or any Outage, suspension, constraint or curtailment in the operation of the Transmission System; or

(g) based on the cost or unavailability of the Energy Source for any reason, including natural causes, unless: (i) transport of the Energy Source to the Seller's Plant is prevented by an event or circumstance that constitutes Force Majeure (as defined in this EPA); or (ii) if the Energy Source is water, wind or solar, the Seller can demonstrate by clear and convincing evidence that the unavailability of the Energy Source is caused by a significant landslide, earthquake or volcanic eruption resulting in a significant reduction in the flow of the Energy Source to the Seller's Plant.

12. LIQUIDATED DAMAGES

12.1 COD Delay - If the Seller's Plant fails to achieve COD by the date that is the earlier of:

(a) 185 days after the Guaranteed COD plus Force Majeure Days, and

(b) the COD Deadline plus Force Majeure Days,

the Seller shall pay COD Delay LDs to the Buyer in an amount equal to the amount determined in accordance with subsection (b) of the definition of "Performance Security" divided by 180 for each day COD is delayed to a maximum of 180 days. The Seller shall pay any COD Delay LDs owing by the Seller to the Buyer in respect of the immediately preceding month on the 30th day after the last day of that month.

12.2 Delivery Shortfalls - If in any month after the first anniversary of COD, the Delivered Eligible Energy during the month is less than 90% of the Monthly Firm Energy Amount for that month, the Seller shall pay LDs to the Buyer calculated as follows:

LD Amount = LD Factor * ((0.9 * Monthly Firm Energy Amount) - Delivered Eligible Energy)

Where:

(a) the Monthly Firm Energy Amount is the amount set out in Appendix 2 for the relevant month less an amount equal to the Monthly Firm Energy Amount divided by the number of minutes in the month for each minute in which the Seller is excused under subsection 7.8(a) from the obligation to deliver Energy; and

(b) "Delivered Eligible Energy" means in each month the amount of Eligible Energy determined pursuant to subsection (a) of the definition of Eligible Energy for that month, but excluding any Energy delivered after the start time and prior to the end time for an

Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4;

(c) LD Factor = the greater of: (i) zero and (ii) A-[(EBP/(1-L))+EBPA]

Where:

(i) A = the lesser of:

(I) the LD Cap; and

(II) the Mid-C Index;

(ii) L = _____%

(iii) EBP = Escalated Bid Price

(iv) EBPA (Escalated Bid Price Adjuster)$_n$ = $____/MWh * CPI$_{\text{January 1 n}}$/CPI $_{\text{January 1 2006}}$

Where:

n = the year for which the Escalated Bid Price Adjuster is being calculated

CPI $_{\text{January 1 n}}$ = the CPI for December in the year immediately preceding the year for which the Escalated Bid Price Adjuster is being calculated.

[Note to Bidders – L will be the greater of (i) zero and (ii) an amount determined from the energy loss information used in the CFT evaluation. EBPA will be the sum of the following: -3.00 if the Green Attributes are transferred to BC Hydro; -3.00 if the Bidder tendered an Hourly Firm Energy Profile; and X if GHG emission offset obligations are transferred to BC Hydro where "X" is the amount determined from the GHG Adjustment Table (CFT Reference Document), based on the Bidder's tendered Guaranteed GHG Intensity.]

(v) Mid-C means the mid-Columbia electricity region;

(vi) "Mid-C Index" means the weighted average for the relevant month of the Dow Jones Mid-C daily firm On-Peak Index and the Dow Jones Mid-C daily firm Off-Peak Index weighted based on the number of on-peak and off-peak hours (as defined in the Mid-C index) in the relevant month. Amounts quoted in U.S. dollars will be converted to Canadian dollars using the average of the Bank of Canada daily "noon rates" for the applicable month;

(vii) "LD Cap" means $100/MWh adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

LD Cap$_n$ = $100/ MWh * CPI$_{\text{January 1 n}}$/CPI $_{\text{January 1 2006}}$

Where:

n = the year for which the escalated LD Cap is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately preceding the year for which the escalated LD Cap is being calculated.

Any LDs owing by the Seller to the Buyer pursuant to this section 12.2 shall be payable on 15th day of the month following the month in which the delivery shortfall occurred.

12.3 Exclusive Remedies for Buyer - Except in the case of Deliberate Breach, payment by the Seller of the LDs in this Article 12 is the exclusive remedy to which the Buyer is entitled for: (i) the Seller's failure to achieve COD by the Guaranteed COD; (ii) the Seller's failure to deliver the Monthly Firm Energy Amount; or (iii) any other failure to comply with section 7.3 or the last sentence of section 6.3, provided that the foregoing does not limit or otherwise affect any right to receive interest on LDs or any right to terminate the EPA, or any right to receive a Termination Payment, in each case as expressly set out in this EPA, or the exercise of any other right or remedy expressly set out in this EPA, including any rights under section 9.5, or Article 13, or any right to apply any invoice adjustments in accordance with Appendix 3.

12.4 Exclusive Remedies for Seller - The Seller's exclusive remedy for the Buyer's failure to take or pay for Eligible Energy is a claim for the price payable by the Buyer for Eligible Energy pursuant to Appendix 3 and any interest on any such amount owing by the Buyer to the Seller, provided that the foregoing does not limit or otherwise affect any right to terminate the EPA, any rights under section 9.5, or any right to receive a Termination Payment expressly set out in this EPA.

12.5 Limits of Liability - Except in the case of Deliberate Breach, in each year during the Term the Seller's liability for damages for all breaches of, or defaults under, this EPA in that year is limited to an amount equal to 200% of the required amount of the Performance Security for the relevant year, provided that the foregoing does not apply to: (i) any liability under any of sections 4.2, 4.5, 5.7, or 6.8; (ii) any liability under section 19.1; (iii) interest on any amount owing under this EPA; (iv) any right to receive a Termination Payment expressly set out in this EPA; or (v) any other provision in this EPA that is expressly excluded from the limits of liability in this section.

12.6 Consequential Damages - Neither Party shall be liable to the other Party for any special, incidental, exemplary, punitive or consequential damages arising out of a Party's performance or non-performance under this EPA, whether based on or claimed under contract, tort, strict liability or any other theory at law or in equity.

13. PERFORMANCE SECURITY

13.1 Delivery - The Parties acknowledge that the Seller has delivered the Performance Security, in the form required pursuant to section 13.4, to the Buyer concurrently with execution and delivery of this EPA. The Seller shall maintain the Performance Security until the time provided in section 13.2. The Performance Security secures the obligations of the Seller under this EPA, but is not a limitation of the Seller's liability in respect of any breach of, or default under, this EPA.

13.2 Return - The Buyer shall return or release the Performance Security to the Seller, without deduction, other than prior deductions, if any, properly made hereunder on the earlier of:

(a) upon termination of this EPA under section 3.1, by the date specified in subsection 3.5(a); or

(b) 10 Business Days after termination of this EPA under subsection 10.2(a), section 15.1 or section 15.2 and discharge of all obligations and liabilities of the Seller to the Buyer under this EPA.

13.3 Enforcement - If:

(a) the Seller fails to pay amounts owing by the Seller to the Buyer pursuant to any of sections 4.2, 4.5, 5.7, or 6.8; or

(b) the Seller fails to pay any Final Amount owing by the Seller to the Buyer; or

(c) the Seller fails to pay any LDs owing by the Seller to the Buyer; or

(d) the Seller fails to pay any Termination Payment owing by the Seller to the Buyer,

and, in each case, the Seller fails to cure such failure to pay within 15 days after notice from the Buyer to the Seller, then the Buyer may enforce the Performance Security and apply the proceeds thereof on account of amounts owing to the Buyer in respect of any or all of the foregoing.

13.4 Form - The Seller shall maintain the Performance Security in the form of a letter of credit that is:

(a) issued or advised by a branch in Vancouver, Canada of a bank or financial institution where the issuing bank or financial institution has a credit rating not less than Standard & Poor's A-, Moody's A3 or Dominion Bond Rating Service A (low) and if such credit rating agencies publish differing credit ratings for the same bank or financial institution, the lowest credit rating of any of the credit rating agencies shall apply for purposes of this section;

(b) in the form set out in Appendix 6, or in such other form as agreed to by the Buyer; and

(c) for a term of not less than one year and must provide that it is renewed automatically, unless the issuing or confirming bank advises otherwise by the date specified in Appendix 6.

13.5 Replenishment - If the Buyer draws on the Performance Security, as permitted hereunder, then the Seller shall within 3 Business Days after such draw provide additional security in the form specified in section 13.4 sufficient to replenish or maintain the aggregate amount of the Performance Security at the amount required hereunder.

13.6 Right to Withhold Payment - If the Seller has failed to maintain the Performance Security at the level required hereunder (subject to the cure period specified in section 13.5), the Buyer shall be entitled to withhold payment of any amount owing by the Buyer to the Seller under this EPA until 5 days after the date when the Seller has delivered the required amount of Performance Security to the Buyer. Any amounts withheld by the Buyer in accordance with this section 13.6 will not bear interest.

13.7 Letter of Credit Failure - The Buyer shall be entitled to enforce the Performance Security in the event of a Letter of Credit Failure and the Buyer shall be entitled to hold the proceeds of such enforcement until such time as the Seller delivers replacement Performance Security in the amount and in the form required under this EPA. Upon receipt of such replacement security, the Buyer shall return the proceeds of enforcement of the original Performance Security to the Seller without interest after deducting any amounts the Buyer is entitled to deduct under this EPA. The Seller shall notify the Buyer promptly of any Letter of Credit Failure.

14. SUSPENSION

14.1 Buyer Suspension - If a Buyer Termination Event has occurred and is continuing, the Buyer may, upon notice to the Seller, suspend performance under this EPA provided that in no event shall any such suspension continue for longer than 90 days and further provided that such right shall not affect the Buyer's obligation to make any payment owing to the Seller in respect of performance by the Seller of its obligations under this EPA prior to the date of suspension by the Buyer.

14.2 Seller Suspension - If a Seller Termination Event has occurred and is continuing, the Seller may, upon notice to the Buyer, suspend performance under this EPA, provided that such right shall not affect the Seller's obligation to pay any amount owing by the Seller to the Buyer in respect of performance of, or failure to perform, the Seller's obligations under this EPA prior to the date of suspension by the Seller.

14.3 Resuming Deliveries - The non-defaulting Party's right to suspend performance pursuant to this Article 14 shall cease when the defaulting Party has demonstrated to the satisfaction of the non-defaulting Party, acting reasonably, that the defaulting Party has cured the cause for the suspension.

15. TERMINATION

15.1 Termination by the Buyer - In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA, the Buyer may terminate this EPA, by notice to the Seller if:

(a) the Seller has failed to obtain all Material Permits by the date that is 365 days prior to the Guaranteed COD, provided that the Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to the date on which the Seller has secured all Material Permits; or

(b) COD does not occur by the earlier of:

(i) the Guaranteed COD plus 365 days plus all Force Majeure Days (not exceeding 365 Force Majeure Days); and

(ii) the COD Deadline plus 180 days plus all Force Majeure Days (not exceeding 185 Force Majeure Days),

provided that the Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to COD, and further provided that if the Buyer has not exercised its right to terminate the EPA within 30 days after the right to terminate arises under this subsection, the Seller may deliver a notice to the Buyer setting out a new date by which the Seller, acting reasonably, expects to achieve COD. If the Buyer does not elect to terminate the EPA within 60 days after receipt of such a notice,

the Buyer shall only be entitled to terminate this EPA under this provision if the Seller does not achieve COD by the date specified in such notice; or

(c) at any time after COD, the Buyer has received a notice from the Seller invoking Force Majeure and:

(i) the Force Majeure has not been removed by the date that is 365 days after the date of the notice invoking Force Majeure; or

(ii) if the Force Majeure cannot be removed within that 365 day period, by the date that is 730 days after the date of the notice invoking Force Majeure, provided that the Seller is working diligently and expeditiously to remove the Force Majeure.

The Buyer shall only be entitled to terminate the EPA under this provision if the Buyer delivers a termination notice prior to the end of the Force Majeure; or

(d) a Buyer Termination Event occurs.

Any termination pursuant to this section 15.1 shall be effective immediately upon delivery of the notice of termination to the Seller.

15.2 Termination by the Seller - In addition to any other right to terminate this EPA expressly set out in any other provision of this EPA, the Seller may terminate this EPA by notice to the Buyer if:

(a) the Seller, after using commercially reasonable efforts, has failed to obtain all Material Permits on terms satisfactory to the Seller, acting reasonably, on or before the date that is 545 days before the Guaranteed COD, provided that if the Seller has not given notice of termination pursuant to this subsection 15.2(a) by the date that is 15 days after the Seller's right to terminate arises under this subsection 15.2(a), the Seller will be deemed to have elected not to terminate this EPA and will not thereafter be entitled to terminate this EPA under this subsection 15.2(a); or

[Note to Bidders: The foregoing subsection will not be included in any EPA where this right to terminate has expired prior to execution of the EPA]

(b) the Seller has received a notice from the Buyer invoking Force Majeure and the Force Majeure has not been removed by the date that is 365 days after the date of notice invoking Force Majeure, provided that the Seller shall only be entitled to terminate the EPA under this provision if the Seller delivers a termination notice prior to the end of the Force Majeure; or

(c) a Seller Termination Event occurs.

Any termination pursuant to this section 15.2 shall be effective immediately upon delivery of the notice of termination to the Buyer.

15.3 Effect of Termination - Upon expiry of the Term or if this EPA is terminated pursuant to section 3.1, subsection 10.2(a) or this Article 15:

(a) the Parties may pursue and enforce any rights and remedies permitted by law or equity in respect of any prior breach or breaches of the EPA, and may enforce any liabilities and obligations that have accrued under this EPA prior to the expiry of the Term or the date of termination (including any claims by the Buyer for amounts that would have been payable by the Seller under any of sections 4.2, 4.5, 5.7 or 6.8 but for the expiry or termination of the EPA), subject to any express restrictions on remedies and limitations or exclusions of liability set out in this EPA; and

(b) (i) with respect to a termination under section 3.1 only, both Parties will remain bound by (A) Article 19 and sections 20.7 and 20.8, and (B) sections 3.3, 3.5, 13.2 and 13.3, in respect of the satisfaction of residual obligations specified to arise on termination only;

(ii) upon expiry of the Term or upon any termination other than a termination under section 3.1:

(A) both Parties will remain bound by: (I) section 7.10; (II) Article 9 in respect of any final billing and resolution of disputed amounts only, (III) Article 13 and Article 15, in respect of the satisfaction of residual obligations specified to arise on termination only; and (IV) Article 19 and sections 20.7 and 20.8; and

(B) the Seller will remain bound by: (I) section 6.5; and (II) for a period of 36 months following expiry of the Term or termination of this EPA, Article 17, with respect to records only,

and, in all such cases, both Parties will remain bound by any other provisions necessary for the interpretation and enforcement of the foregoing provisions.

15.4 Payment on Termination by the Buyer

(a) If the Buyer terminates this EPA under section 15.1, except for a termination pursuant to subsection 15.1(c), the Seller shall pay to the Buyer an amount equal to $60,000/MW multiplied by the Plant Capacity where termination occurs prior to the first anniversary of COD, or, where termination occurs on or after the first anniversary of COD, an amount equal to $40,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

(b) If the Buyer terminates this EPA under subsection 15.1(c), no Termination Payment is payable by the Seller to the Buyer, except as set out in subsection 15.4(c).

(c) If the Buyer terminates this EPA under subsection 15.1(c) prior to the first anniversary of COD, the Seller shall reimburse the Buyer, within 30 days after the date of delivery by the Buyer to the Seller of an invoice therefor (which invoice shall be delivered not later than 60 days after the date of termination of the EPA), for an amount, not exceeding the amount of the Performance Security required hereunder, equal to the Network Upgrade Costs.

15.5 Payment on Termination by the Seller

(a) If the Seller terminates this EPA under subsection 15.2(a), the Seller shall pay to the Buyer an amount equal to $20,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

(b) If the Seller terminates this EPA under subsection 15.2(b), no Termination Payment is payable by the Buyer to the Seller.

(c) If the Seller terminates this EPA under subsection 10.2(a), no Termination Payment is payable by the Seller to the Buyer except that if the Seller terminates the EPA under subsection 10.2(a) prior to the first anniversary of COD, subsection 15.4(c) applies.

(d) If the Seller terminates this EPA under subsection 15.2(c) prior to COD, the Buyer shall pay to the Seller an amount equal to the lesser of:

(i) 115% of the Development Costs; and

(ii) the positive amount, if any, by which the Seller's Losses and Costs exceed its aggregate Gains.

(e) If the Seller terminates this EPA under subsection 15.2(c) after COD, the Buyer shall pay to the Seller an amount equal to the positive amount, if any, by which the Seller's Losses and Costs exceed its aggregate Gains.

(f) The Buyer may audit the Seller's Development Costs and in that event, the Seller shall provide all reasonable cooperation to the Buyer or its designated representative, including access to all original records related to Development Costs.

(g) The Seller's Gains, Losses and Costs shall be determined by comparing the value of the remaining Term, contract quantities and price payable under this EPA had it not been terminated to the relevant market prices for equivalent quantities for the remaining Term either quoted by a bona fide arm's length third party or which are reasonably expected to be available in the market under a replacement contract for this EPA. Market prices will be adjusted for differences between the product subject to the market prices and the product specified under this EPA including with respect to quantity, place of delivery and length of term.

(h) The Seller shall not be required to enter into a replacement transaction in order to determine the amount payable by the Buyer pursuant to subsection 15.5(d) or (e).

(i) The Seller shall determine the amount of any Termination Payment owed by the Buyer pursuant to subsection 15.5(d) or (e) as applicable and shall notify the Buyer of such amount and provide reasonable particulars with respect to its determination within 120 days after the effective date of termination of this EPA, failing which the Seller will not be entitled to any Termination Payment under this section.

(j) If the Seller's aggregate Gains exceed its aggregate Losses and Costs, if any, resulting from the termination of this EPA, the amount of the Termination Payment shall be zero.

(k) The Seller's Gains, Losses and Costs will be discounted to the present value of those Gains, Losses and Costs at the effective date of termination of the EPA (to take into account the time value of money for the period between the effective date of termination of the EPA and the date the Gains, Losses and Costs would have occurred but for the termination of the EPA) using the Present Value Rate applicable at the effective date of termination of the EPA, where the "Present Value Rate" means the annual yield on a Government of Canada Bond having a maturity date that most closely matches the date on which the Term would have expired but for the termination of the EPA, plus 3%.

15.6 Termination Payment Date - A Party required to make a Termination Payment to the other Party shall, except in the case of a Termination Payment payable pursuant to subsection 15.5(d) or (e), pay the Termination Payment within 5 Business Days after the effective date of termination of this EPA. The Buyer shall pay any Termination Payment owing by the Buyer pursuant to subsection 15.5(d) or (e) within 30 Business Days after the date of delivery of an invoice by the Seller to the Buyer pursuant to subsection 15.5(d) or (e) as applicable. At the time for payment of the Termination Payment, each Party shall pay to the other Party all additional amounts payable by it pursuant to this EPA, but all such amounts will be netted and aggregated with any Termination Payment.

15.7 Exclusive Remedies - Subject to section 15.3, the payments and actions contemplated by section 3.5 shall be the exclusive remedy to which the Parties are entitled for termination of this EPA pursuant to section 3.1. Except in the case of Deliberate Breach or as otherwise expressly set out in this EPA, and subject to section 15.3: (a) payment by the Seller of the Termination Payment is the exclusive remedy to which the Buyer is entitled for termination of this EPA pursuant to subsections 15.1(a), (b) or (d) or 15.2(a); and (b) payment by the Seller of any amount payable pursuant to subsection 15.4(c) is the exclusive remedy to which the Buyer is entitled for termination of this EPA pursuant to subsection 15.1(c). Payment by the Buyer of the Termination Payment is the exclusive remedy to which the Seller is entitled for termination of this EPA pursuant to subsection 15.2(c). Termination of this EPA is the exclusive remedy to which the Seller is entitled for termination of this EPA pursuant to subsection 15.2(b).

16. ASSIGNMENT

16.1 Assignment - A Party may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term, except:

(a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditioned; or

(b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's ownership interest in the Seller's Plant, or of all or any interest of the Seller

in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

16.2 Preconditions to Assignment - Without limiting subsection 16.1(a), any assignment pursuant to section 16.1 (other than an assignment to a Facility Lender) is subject to:

(a) the assignee entering into and becoming bound by this EPA, assuming all the obligations and liabilities of the assignor under the EPA arising both before and after the assignment of the EPA, providing any Performance Security, as applicable at the time of assignment and providing the representations and warranties set out in section 18.1 effective as at the time of assignment; and

(b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller, the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

16.3 Assignment to Facility Lender - If the Seller seeks consent to assign this EPA to a Facility Lender or Facility Lenders, the Seller acknowledges that the Buyer is entitled to require, as a condition of the Buyer's consent to such assignment, that the Seller and the Facility Lender enter into an agreement with the Buyer substantially in the form attached as Appendix 7.

16.4 No Implied Consent to Exercise of Rights - No consent to any assignment given by the Buyer under this Article 16 implies or constitutes a consent to the exercise by the assignee, or any Affiliate of the assignee, whether or not a Facility Lender, of any right if the exercise of that right, at the time it was acquired, would require the consent of the Buyer under this Article 16, and the exercise of any such right will require the further consent of the Buyer.

16.5 Costs - The assignor shall reimburse the other Party for all costs reasonably incurred in connection with an assignment.

16.6 No Assignment Before COD - Notwithstanding subsection 16.1(a), the Seller shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

17. INSPECTION

For the sole purpose of verifying compliance with this EPA, of verifying the accuracy of invoices and other statements or calculations delivered by the Seller to the Buyer under this EPA and of verifying the Seller's right to rely on any relief claimed by the Seller under this EPA, on reasonable prior notice to the Seller, the Seller shall provide the Buyer and the Buyer's representatives and advisors with prompt access during normal business hours to the Seller's Plant and to the records relating to the Seller's Plant including all records required to be maintained by the Seller under section 6.5 and the Seller shall promptly provide copies of any such records to the Buyer on request by the Buyer at any time. The Buyer and the Buyer's representatives and advisors may take copies of all such records. All such records that contain confidential technical or proprietary information are Confidential Information under section 20.8. The Buyer shall exercise any access under this Article 17 at the Buyer's cost and in a manner that minimizes disruption to the operation of the Seller's Plant. Any review, inspection or audit by the Buyer of the Seller's Plant, its design, construction, operation, maintenance, repair, records or other activities of the Seller may not be relied upon by the Seller, or others, as confirming or approving those matters.

18. REPRESENTATIONS AND WARRANTIES

18.1 By Seller - The Seller represents and warrants to the Buyer, and acknowledges that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

(a) **Corporate Status** - The Seller is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) **Bankruptcy** - No actions have been taken or authorized by the Seller or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller;

(c) **Assets** - No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

(d) **No Conflict** - Neither the signing of this EPA, nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Seller, any permit, franchise, lease, license, approval or agreement to which the Seller is a party, or any other covenant or obligation binding on the Seller or affecting any of its properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) **Binding Obligation** - This EPA constitutes a valid and binding obligation of the Seller enforceable against the Seller in accordance with its terms;

(f) **Authorization, Execution and Delivery** - This EPA has been duly authorized, executed and delivered by the Seller;

(g) **Bid Documents** - All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) **Exemption From Regulation** - The Seller is exempt from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

18.2 By Buyer - The Buyer represents and warrants to the Seller, and acknowledges that the Seller is relying on those representations and warranties in entering into this EPA, as follows:

(a) **Corporate Status** - The Buyer is a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, is validly existing and is in good standing under the laws of British Columbia, is lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

(b) **Bankruptcy** - No actions have been taken or authorized by the Buyer or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Buyer or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Buyer;

(c) **Assets** - There is no appropriation, expropriation or seizure of any of the material assets of the Buyer pending or threatened;

(d) **No Conflict** - Neither the signing of this EPA nor the carrying out of the Buyer's obligations under this EPA will constitute or cause a breach of, default under, or violation of, the *Hydro and Power Authority Act* (British Columbia), any permit, franchise, lease, license, approval or agreement to which the Buyer is a party, or any other covenant or obligation binding on the Buyer or affecting any of its properties;

(e) **Binding Obligation** - This EPA constitutes a valid and binding obligation of the Buyer enforceable against the Buyer in accordance with its terms; and

(f) **Authorization, Execution and Delivery** - This EPA has been duly authorized, executed and delivered by the Buyer.

19. INDEMNITIES

19.1 Seller Indemnity - The Seller shall indemnify, defend and hold harmless the Buyer and its shareholder(s) and Affiliates, and their respective directors, officers, employees, agents, representatives, successors and permitted assigns (the "**Buyer Indemnified Parties**") from and against all claims, demands, actions, causes of action, suits, orders and proceedings made or brought against any of the Buyer Indemnified Parties:

(a) with respect to any emissions from the Seller's Plant; or

(b) for personal injury, including death, to third Persons and for damage to property of third Persons, to the extent caused or contributed to by the wilful act or omission or negligence of the Seller, any contractor or subcontractor or supplier to the Seller or any director, officer, employee or agent of the Seller or any other Person for whom the Seller is responsible at law where such wilful act or omission or negligence is in connection with the Project or the performance of, or the failure to perform, any of the Seller's obligations under this EPA.

19.2 Buyer Indemnity - The Buyer shall indemnify, defend and hold harmless the Seller and its shareholder(s) and Affiliates, and their respective directors, officers, employees, agents, representatives, successors and permitted assigns (the "**Seller Indemnified Parties**") from and against all claims, demands, actions, causes of action, suits, orders and proceedings made or brought against any of the Seller Indemnified Parties for personal injury, including death, to third Persons and for damage to property of third Persons, to the extent caused or contributed to by the wilful act or omission or negligence of the Buyer, any contractor or subcontractor or supplier to the Buyer or any director, officer, employee or agent of the Buyer or any other person for whom the Buyer is responsible at law while the Buyer or any such Person is at the Seller's Plant.

19.3 Indemnification Conditions - The right of a Party ("**Indemnitee**") to be indemnified by the other Party ("**Indemnitor**") under any indemnity contained in this EPA in respect of a claim by a third Person is subject to the conditions that:

(a) the Indemnitee gives the Indemnitor prompt notice of such claim, the right to select and instruct counsel, and all reasonable cooperation and assistance, including the availability of documents and witnesses within the control of the Indemnitee, in the defence or settlement of the claim; and

(b) the Indemnitee does not compromise or settle the claim without the prior written consent of the Indemnitor.

20. GENERAL PROVISIONS

20.1 Electric Service to the Seller - If at any time the Buyer makes electric service available to the Seller's Plant, then that service will be provided under and in accordance with the Buyer's electric tariff applicable at the relevant time, and not under this EPA.

20.2 Independence - The Parties are independent contractors and nothing in this EPA or its performance creates a partnership, joint venture or agency relationship between the Parties.

20.3 Enurement - This EPA enures to the benefit of the Parties, their successors and their permitted assigns.

20.4 Notices - Any notice, consent, waiver, declaration, request for approval or other request, statement or bill (a "**notice**") that either Party may be required or may desire to give to the other Party under this EPA must be in writing addressed to the other Party at the address stated in subsection 20.4(c) or (d) and:

(a) may be delivered by hand or by a courier service during normal business hours on a Business Day, in which case the notice will be deemed to have been delivered on that Business Day;

(b) notices, other than notices under section 3.4, 4.2, or 7.2 or any of Articles 11, 13, 14, 15 or 16, may be sent by email during normal business hours on a Business Day, in which case provided that the Party delivering the notice obtains a confirmation of delivery, the notice will be deemed to have been delivered on that Business Day;

(c) subject to subsection 20.4(e), the address of the Buyer for notices is as set out in Appendix 9;

(d) subject to subsection 20.4(e), the address of the Seller for notices is as set out in Appendix 9 and the Buyer may, but is not required to (except as otherwise provided in a Lender Consent Agreement, if any) provide a copy of any such notice to the Facility Lender; and

(e) either Party may change its address or fax number for notices under this EPA by notice to the other Party.

20.5 Entire Agreement and Amendment - This EPA contains the entire agreement between the Parties with respect to the purchase and sale of Energy and supersedes all previous communications, understandings and agreements between the Parties with respect to the subject matter hereof including, without limitation, the Call for Tenders issued by the Buyer on 8 December 2005 and all Addenda, questions and answers and any other communications of any kind whatsoever by the Buyer in connection therewith or relating thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements express, implied or statutory between the Parties other than as expressly set out in this EPA. This EPA may not be amended, except by an agreement in writing signed by both Parties.

20.6 No Waiver - Other than in respect of the specific matter or circumstance for which a waiver is given, and except as otherwise specified in this EPA, no failure by a Party to enforce, or require a strict observance and performance of, any of the terms of this EPA will constitute a waiver of those terms or affect or impair those terms or the right of a Party at any time to enforce those terms or to take advantage of any remedy that Party may have in respect of any other matter or circumstance.

20.7 Dispute Resolution - If any dispute arises under or in relation to this EPA, that dispute will be referred to and finally resolved by arbitration by a single arbitrator. The arbitration will be administered by the British Columbia International Commercial Arbitration Centre ("**BCICAC**") pursuant to its rules. The place of arbitration will be Vancouver, British Columbia. If at the time a dispute arises the BCICAC does not exist, the dispute will be finally settled by arbitration by a single arbitrator who, failing agreement of the parties, shall be appointed under the *Commercial Arbitration Act (British Columbia)* or under the *International Commercial Arbitration Act (British Columbia)*, as applicable, and the arbitrator shall conduct the arbitration in accordance with such rules as the Parties may agree in writing, or failing agreement, such rules as may be determined or adopted by the arbitrator. The decision of the arbitrator will be final and binding on the Parties. The arbitrator will have jurisdiction and power to make interim, partial or final awards ordering specific performance, injunction and any other equitable remedy. The Parties are entitled to seek interim measures of protection from the courts pending completion of any arbitration. All performance required under this EPA by the Parties and payments required under this EPA will continue during the dispute resolution proceedings contemplated by this section 20.7, provided that this section may not be interpreted or applied to delay or restrict the exercise of any right to suspend performance under or terminate this EPA pursuant to the express terms hereof. Any payments or reimbursements required by an arbitration award will be due as of the date determined in accordance with section 9.2 or, where section 9.2 is not applicable, as of the date determined in the award, and, without duplication with subsection 9.2(b), will bear interest at an annual rate equal to the Prime Rate plus 3%

compounded monthly, from the date such payment was due until the amount is paid. To the fullest extent permitted by law, the Parties shall maintain in confidence the fact that an arbitration has been commenced, all documents and information exchanged during the course of the arbitration proceeding, and the arbitrators' award, provided that each of the Parties shall be entitled to disclose such matters to its own officers, directors, shareholders and employees, its professional advisors and other representatives, and may make such disclosures in the course of any Proceedings required to pursue any legal right arising out of or in connection with the arbitration and may make such disclosures as are required by law or for regulatory purposes. Nothing in this EPA precludes either Party from bringing a Proceeding in any jurisdiction to enforce an arbitration award or any judgement enforcing an arbitration award, nor will the bringing of such Proceedings in any one or more jurisdictions preclude the bringing of enforcement Proceedings in any other jurisdiction. In connection with any court proceedings, each Party waives its respective rights to any jury trial.

20.8 Confidentiality

(a) Without limiting any other confidentiality agreement between the Parties, during the Term and for 5 years thereafter, the Buyer shall treat as confidential and will not cause or permit the publication, release or disclosure of any Confidential Information received by the Buyer from the Seller, except to the extent that publication, release or disclosure: (i) is expressly authorized under any section of this EPA; (ii) is necessary to enable the Buyer to fulfil its obligations under this EPA, including under section 3.3; (iii) is required by law or for regulatory purposes; (iv) is made with the prior consent of the Seller; or if (v) such information has entered the public domain other than through the actions of the Buyer. The Buyer may also disclose Confidential Information: (vi) to consultants and advisors to the Buyer and representatives of the Government of British Columbia who have a need to know the Confidential Information and who have been informed by the Buyer of the need to maintain the confidentiality of the Confidential Information disclosed to them; (vii) as may be necessary for the Buyer to adequately pursue or defend any legal or regulatory proceeding relating to the CFT or this EPA or any EPA awarded under the CFT process; and (viii) as otherwise set out in this EPA.

(b) The Seller acknowledges that the Buyer is subject to the *Freedom of Information and Protection of Privacy Act* (British Columbia) and agrees that the Buyer's non-disclosure obligations under this EPA are subject to the provisions of that legislation.

(c) The Parties confirm that Confidential Information constitutes commercial and financial information of the Seller, which has been supplied, or may be supplied, in confidence and the disclosure of which could reasonably be expected to harm significantly the competitive position and/or interfere significantly with the negotiating position of the Seller. Accordingly, the Parties confirm their intention that all Confidential Information disclosed by the Seller to the Buyer shall be deemed to be confidential and exempt from disclosure to third persons in accordance with section 21 of the *Freedom of Information and Protection of Privacy Act* (British Columbia), as amended from time to time.

20.9 Distribution Authority - This EPA shall be interpreted and applied as though the Distribution Authority were a third party, including for purposes of determining whether or not a Force Majeure has occurred.

20.10 Commodity Contract/Forward Contract - The Parties agree and intend that this EPA constitutes a commodity contract for the purposes of subsection (h) of the definition of "eligible financial

contract" in section 65.1(8) of the *Bankruptcy and Insolvency Act* (Canada) and in Section 11.1(1) of the *Companies' Creditors Arrangement Act* (Canada) and that this EPA and the transactions contemplated under this EPA constitute a "forward contract" within the meaning of section 556 of the United States Bankruptcy Code and that the Parties are "forward contract merchants" within the meaning of the United States Bankruptcy Code.

20.11 Further Assurances - Each Party shall, upon the reasonable request of the other Party, do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required for the performance of this EPA.

20.12 Severability - Any provision of this EPA, which is illegal or unenforceable will be ineffective to the extent of the illegality or unenforceability without invalidating the remaining provisions of this EPA.

20.13 Counterparts - This EPA may be executed in counterparts, each of which is deemed to be an original document and all of which are deemed one and the same document.

IN WITNESS WHEREOF each Party by its duly authorized representative(s) has signed this EPA as of the date set out on page 1 of this EPA.

For ●

_____
Authorized Representative

_____
Print Name and Office

_____
Date

For **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY:**

_____
Authorized Representative

_____
Print Name and Office

_____
Date

APPENDIX 1

DEFINITIONS

References in an Appendix to a section or subsection mean a section or subsection of the EPA, and not an Appendix, unless otherwise stated. The following words and expressions wherever used in this EPA have the following meaning:

1. "**Affiliate**" means, with respect to the Seller, any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly, by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

2. "**Annual Operating Plan**" means each plan delivered by the Seller to the Buyer under subsection 6.6(b) and all amendments to such plan in accordance with subsection 6.6(b).

3. "**Authorized Planned Outage**" means a Planned Outage that is scheduled in accordance with Good Utility Practice, complies with the requirements of section 6.4 and does not exceed the duration of the Planned Outage set out in the notice of the Planned Outage delivered by the Seller under section 6.4.

4. "**Bankrupt or Insolvent**" means, with respect to a Person:

   (a) the Person has started proceedings to be adjudicated a voluntary bankrupt or consented to the filing of a bankruptcy proceeding against it; or

   (b) the Person has filed a petition or similar proceeding seeking reorganization, arrangement or similar relief under any bankruptcy or insolvency law; or

   (c) a receiver, liquidator, trustee or assignee in bankruptcy has been appointed for the Person or the Person has consented to the appointment of a receiver, liquidator, trustee or assignee in bankruptcy; or

   (d) the Person has voluntarily suspended the transaction of its usual business; or

   (e) a court has issued an order declaring the Person bankrupt or insolvent.

5. "**BCUC**" means the British Columbia Utilities Commission or any successor thereto.

6. "**BCUC Acceptance**" has the meaning given in section 3.1.

7. "**BC Clean Electricity**" means electricity that meets the requirements set out in the "BC Clean Electricity Guidelines" issued by the British Columbia Ministry of Energy, Mines and Petroleum Resources" dated 15 September, 2005, as amended at any time prior to the first anniversary of COD.

8. "**Bid Documents**" means the Tender and all documents and information provided by the Seller to the Buyer in connection with such Tender, whether concurrently with or after the date of submission of the Tender to the Buyer.

9. "**Business Day**" means any calendar day which is not a Saturday, Sunday or other day recognized as a statutory holiday in British Columbia.

10. "**Buyer**" means British Columbia Hydro and Power Authority and its successors and permitted assigns.

11. "**Buyer Termination Event**" means any one of the following:

    (a) the Seller is Bankrupt or Insolvent;

    (b) a Letter of Credit Failure has occurred and the Seller has failed to deliver a replacement Performance Security within 5 Business Days after the Letter of Credit Failure occurred;

    (c) the Seller has not, by the date that is the earlier of: (i) 60 days after the date of award of this EPA under the CFT; and (ii) 240 days after the date of issuance by the Transmission Authority to the Seller of the F2006 CFT Preliminary Interconnection Study Report, executed and delivered to, or caused to be executed and delivered to, the Transmission Authority a Combined Study Agreement for the Seller's Plant together with the applicable fee, in the form and amount prescribed by the Transmission Authority;

    (d) except where an amount has been disputed in the manner specified in subsection 9.1(b), an amount due and payable by the Seller to the Buyer under this EPA remains unpaid for 15 days after its due date and such default has not been cured within 15 days after the Buyer has given notice of the default to the Seller; or

    (e) the Seller is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), unless within 30 days after the date of notice by the Buyer to the Seller of the default the Seller has cured the default or, if the default cannot be cured within that 30 day period, the Seller demonstrates to the reasonable satisfaction of the Buyer that the Seller is working diligently and expeditiously to cure the default and the default is cured within a further reasonable period of time. A "material default" includes any failure by the Seller to comply with subsection 6.3(f) or any of sections 6.8, 6.11 or 7.5, any Deliberate Breach by the Seller of its obligations under section 7.3, and any purported assignment of this EPA without the consent of the Buyer where such consent is required under Article 16. A "material default" does not include any failure, other than a failure resulting from a Deliberate Breach, to deliver the Monthly Firm Energy Amount in respect of which failure the Seller has paid any LDs owing under section 12.2.

12. "**CFT** " means the "F2006 Open Call for Power - Call for Tenders" issued by the Buyer on 8 December 2005, together with all Addenda thereto, and all other documents and forms referenced therein as forming part of the CFT.

13. "**COD**" or "Commercial Operation Date" means the time when the Seller's Plant achieves COD pursuant to section 5.2.

14. "**COD Certificate**" means a certificate in the form set out in Appendix 4 signed by a senior officer of the Seller.

15. **"COD Deadline"** means **_____**. ***[Note to Bidders: For bidders with a Guaranteed COD on or before 1 November 2009, the COD Deadline is 1 November 2009. For***

bidders with a Guaranteed COD after 1 November 2009, the COD Deadline is 1 November 2010]

16. "**COD Delay LDs**" means the LDs specified in section 12.1.

17. "**Combined Study Agreement**" means an agreement, in prescribed form, between the Seller and the Transmission Authority wherein the Seller contracts with the Transmission Authority for an interconnection impact study and interconnection facility study.

18. "**Compliance Units**" means any credit, offset, unit, allowance or other instrument that may be used to achieve compliance with emission limitation or intensity obligations as prescribed under Laws and Permits regulating GHG emissions from the Seller's Plant.

19. "**Confidential Information**" means: (i) information that is described as confidential information in any section of this EPA; and (ii) information disclosed by the Seller to the Buyer in the CFT process and that is described in the CFT as confidential.

20. "**Construction Insurance**" means all insurance generally accepted in the insurance industry as being required to construct a facility similar to the Seller's Plant, including course of construction insurance.

21. "**Control**" of any Person means: (i) with respect to any corporation or other Person having voting shares or the equivalent, the ownership or power to vote, directly or indirectly, shares, or the equivalent, representing 50% or more of the power to vote in the election of directors, managers or persons performing similar functions; (ii) ownership of 50% or more of the equity or beneficial interest in that Person; or (iii) the ability to direct the business and affairs of any Person by acting as a general partner, manager or otherwise.

22. "**Costs**" means brokerage fees, commissions and other similar transaction costs and expenses reasonably incurred or that would reasonably be expected to be incurred by the Seller in entering into new arrangements which replace this EPA, and legal fees, if any, incurred in connection with enforcing the Seller's rights under this EPA.

23. "**Deliberate Breach**" means:

    (a) any failure by the Seller to achieve COD by the earlier of: (i) Guaranteed COD plus 365 days plus all Force Majeure Days (not exceeding 365 Force Majeure Days); and (ii) the COD Deadline plus 180 days plus all Force Majeure Days (not exceeding 185 Force Majeure Days), resulting from any wilful or grossly negligent act or omission of the Seller;

    (b) any breach of or default under any provision of this EPA by the Seller resulting from any wilful or grossly negligent act or omission by the Seller;

    (c) a Buyer Termination Event constituting a repudiation of the EPA by the Seller; or

    (d) any sale or transfer by the Seller of Energy to any Person, other than the Buyer, except where such sale or transfer is expressly permitted under this EPA.

24. "**Development Costs**" means all costs reasonably incurred or committed by the Seller, after the date of issuance of the CFT, for the Project and all costs reasonably incurred, or that are

reasonably likely to be incurred by the Seller, after taking reasonable mitigation measures, to terminate all contractual commitments with respect to the Project and to otherwise cease development of the Project, but excluding any lost profits, loss of opportunity costs or damages and all other special, incidental, indirect or consequential losses.

25. "**Direct Assignment Costs**" means all costs of design, engineering, procurement, construction, installation and commissioning of Direct Assignment Facilities incurred by the Transmission Authority (in respect of the Transmission System) and/or the Distribution Authority (in respect of the Distribution System).

26. "**Direct Assignment Facilities**" means modifications or additions to transmission, or distribution, related facilities that are integrated with the Transmission System or the Distribution System, as the case may be, that are required to accommodate the interconnection of the Seller's Plant and are for the sole benefit of the Seller's Plant, as determined by the Transmission Authority (as to the Transmission System) or the Distribution Authority (as to the Distribution System).

27. "**Distribution Authority**" means the Person or Persons who is or are responsible for the planning, asset management, and operation of the Distribution System, in whole or in part, including an independent system operator.

28. "**Distribution System**" means the distribution, protection, control and communication facilities in British Columbia that are or may be used in connection with, or that otherwise relate to, the transmission of electrical energy at 35kV or less, and includes all additions and modifications thereto and repairs or replacements thereof.

29. "**EcoLogo^{M} Certification**" means certification pursuant to Environment Canada's Environmental Choice^{M} program confirming that the Seller's Plant and all or part of the Energy complies with the "Guideline on Renewable Low-Impact Electricity", as amended from time to time and is therefore entitled to the EcoLogo^{M} designation.

30. "**Effective Date**" means the date set out on page one hereof.

31. "**Eligible Energy**" means in each month after COD:

    (a) the amount of Metered Energy delivered by the Seller at the POI in that month, but excluding any portion of the Metered Energy that at any time exceeds 120% of the Plant Capacity; and

    (b) Energy that is deemed to be "Eligible Energy" in that month pursuant to section 7.9.

32. "**Energy**" means electric energy expressed in MWh generated by the Seller's Plant excluding Station Service.

33. "**Energy Source**" means the source of energy used to generate Energy at the Seller's Plant as specified in Appendix 5.

34. "**Escalated Bid Price**" has the meaning given in Appendix 3.

35. "**F2006 CFT Preliminary Interconnection Study Report**" means the report referenced in section 7 of Appendix 5.

36. "**Facilities Agreement**" means the agreement between the Seller and the Transmission Authority setting out the commercial terms and conditions applicable to the construction of the Direct Assignment Facilities and Network Upgrades as amended or replaced from time to time.

37. "**Facility Lender**" means any lender(s) providing any debt financing for the Project and any successors or assigns thereto.

38. "**Final Amount**" means an amount owing by either Party to the other Party pursuant to this EPA (including as a result of a breach of this EPA) where such amount is: (a) undisputed by the Party owing such amount; or (b) has been finally determined by an arbitration award pursuant to section 20.7 or by a court order and all rights of appeal in respect of such award or order have been exhausted or have expired.

39. "**Firm Energy**" has the meaning given in Appendix 3.

40. "**Force Majeure**" means, subject to the exclusions in section 11.2, any event or circumstance not within the control of the Party claiming Force Majeure and, to the extent not within that Party's control, includes:

    (a) acts of God, including wind, ice and other storms, lightning, floods, earthquakes, volcanic eruptions and landslides;

    (b) strikes, lockouts and other industrial disturbances, provided that settlement of strikes, lockouts and other labour disturbances will be wholly within the discretion of the Party involved;

    (c) epidemics, war (whether or not declared), blockades, acts of public enemies, acts of sabotage, civil insurrection, riots and civil disobedience;

    (d) acts or omissions of Governmental Authorities, including delays in regulatory process and orders of a regulatory authority or court of competent jurisdiction;

    (e) explosions and fires; and

    (f) notwithstanding subsection 11.2(f), an inability of the Seller to achieve COD solely as a result of a delay by the Transmission Authority in completion of Direct Assignment Facilities or Network Upgrades and such delay is not attributable to the Seller or the Seller's Plant, including any change to the point of interconnection with the Transmission System or other Project change made by the Seller under section 4.5,

    but does not include:

    (g) any refusal, failure or delay of any Governmental Authority in granting any Material Permit to the Seller, whether or not on terms and conditions that permit the Seller to perform its obligations under this EPA, except where such failure or delay is a result of an event described in paragraph (a), (b), (c) or (e) above.

41. "**Force Majeure Days**" means the number of days the Seller is delayed in achieving COD as a result of Force Majeure invoked by the Seller in accordance with Article 11.

42. "**Forced Outage**" means a partial or total interruption in the delivery of, or ability to deliver, Energy that is not a result of an Authorized Planned Outage or a Force Majeure.

43. "**Gains**" means an amount equal to the present value of the economic benefit (exclusive of Costs), if any, to the Seller resulting from the termination of this EPA, determined in a commercially reasonable manner.

44. "**GHG**" or "**Greenhouse Gas(es)**" means: (i) one or more of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride; and (ii) any other gas that is identified as having significant global warming potential and is added, at any time before the expiry of the Term, to Schedule 1 to the *Canadian Environmental Protection Act, 1999* or to any other regulation(s) governing the emission of the gases noted in (i) from the Seller's Plant.

45. "**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the WECC region.

46. "**Governmental Authorities**" means any federal, provincial, local or foreign governments or any of their boards or agencies, or any regulatory authority, other than the Buyer and the Seller and entities controlled by the Buyer or the Seller.

47. "**Green Attributes**" means:

    (a) all attributes associated with, or that may be derived from, the Energy and/or the Seller's Plant having decreased environmental impacts, including any existing or future credit, allowance, "green" tag, ticket, certificate or other "green" marketing attribute or proprietary or contractual right, whether or not tradeable, resulting from the Energy during the Term;

    (b) any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable and any other proprietary or contractual right, whether or not tradeable, resulting from, or otherwise related to: (i) the actual or assumed reduction, displacement or offset of emissions at any location other than the Seller's Plant as a result of the generation, purchase or sale of the Energy; or (ii) the reduction, removal, avoidance, sequestration or mitigation of emissions at or from the Seller's Plant; and

    (c) all revenues, entitlements, benefits and other proceeds arising from or related to the foregoing.

48. "**GST**" means the goods and services tax imposed under the Excise Tax Act (Canada) as that Act may be amended or replaced from time to time.

49. "**Guaranteed COD**" means _____TO#1_____.

50. "**Interconnection**" means the facilities and procedures that permit the flow of electric power from the Seller's Plant to the Transmission System and vice versa.

51. "**Interconnection Agreement**" means the agreement between the Seller and the Transmission Authority which provides for the implementation and operation of the Interconnection, as amended or replaced from time to time.

52. "**kV**" means kilovolts.

53. "**Laws**" means any and all statutes, laws (including common law), ordinances, rules, regulations, codes, orders, bylaws, policies, directions, standards, guidelines, protocols and other lawful requirements of any Governmental Authority.

54. "**LDs**" means liquidated damages payable by the Seller to the Buyer under Article 12.

55. "**Lender Consent Agreement**" means an agreement referred to in section 16.3.

56. "**Letter of Credit Failure**" means:

    (a) a failure to renew or substitute the Performance Security by no later than 60 days prior to the expiry thereof;

    (b) the issuer of the Performance Security fails to maintain a credit rating of at least the minimum rating specified in section 13.4;

    (c) the issuer of the Performance Security fails to comply with or perform its obligations under the Performance Security;

    (d) the issuer of the Performance Security disaffirms, disclaims, repudiates, terminates, rejects, in whole or in part, or challenges the validity of, the Performance Security; or

    (e) the Performance Security fails or ceases to be in full force and effect for purposes of this EPA (whether or not in accordance with its terms) prior to the date specified in Article 13 for return of the Performance Security to the Seller.

57. "**Long Term Operating Plan**" means the plan referred to in subsection 6.6(a) as amended by the Seller from time to time.

58. "**Losses**" means an amount equal to the present value of the economic loss (exclusive of Costs), if any, to the Seller resulting from the termination of this EPA, determined in a commercially reasonable manner.

59. "**Major Damage**" means damage where the cost to repair the damage exceeds the present value (using the Present Value Rate) of (a) the projected Energy deliveries from the Seller's Plant for the remainder of the Term, multiplied by (b) the projected payments under this EPA for that Energy, (calculated on the basis that the Tier 2 Non-Firm Energy Price will be equal to the Tier 1 Non-Firm Energy Price), less a $/MWh amount representing the estimated operating and maintenance costs for the Seller's Plant (including costs of the Energy Source).

60. "**Material Permits**" means all of the following if and as required for the Seller's Plant:

    (a) environmental assessment certificate;

(b) air emissions permit;

(c) any permits, licenses or approvals required with respect to the discharge of any type of waste liquids from the Seller's Plant;

(d) water licence;

(e) zoning appropriate for the Seller's Plant;

(f) any subdivision approvals required to create the site on which the Seller's Plant is or will be located as a separate legal parcel;

(g) any permits or approvals required with respect to the storage of the Energy Source at the Seller's Plant; and

(h) any lease, license or occupation or similar agreement required with respect to the Seller's Plant including all access roads to the Seller's Plant,

on terms and conditions that permit the Seller to comply with its obligations under this EPA.

61. "**Metered Energy**" means Energy recorded by the Metering Equipment.

62. "**Metering Equipment**" means the metering equipment described in section 8.1.

63. "**Monthly Firm Energy Amount**" means the amount of Energy the Seller is required to deliver to the Buyer at the POI in each month of the Term after COD as set out in Appendix 2.

64. "**Monthly Firm Energy Delivery Rate**" means the Monthly Firm Energy Amount for the relevant month as set out in Appendix 2 divided by the number of hours in that month.

65. "**MW**" means megawatt.

66. "**MWh**" means megawatt-hour.

67. "**NERC**" means the North American Electric Reliability Council or a successor organization.

68. "**Network Upgrades**" means modifications or additions to transmission, or distribution, related facilities that are integrated with and support the overall Transmission System or Distribution System, as the case may be, that are required to accommodate the interconnection of the Seller's Plant to the system and to transmit the electricity from the Seller's Plant through the system to the Buyer's network loads, but which benefit all users of the system, as determined by the Transmission Authority (as to the Transmission System) or the Distribution Authority (as to the Distribution System).

69. "**Network Upgrade Costs**" means all costs incurred by the Transmission Authority (in respect of the Transmission System) and/or the Distribution Authority (in respect of the Distribution System) for the design, engineering, procurement, construction, installation and commissioning of Network Upgrades.

70. "**Outage**" means:

(a) in the case of the Seller's Plant, a partial or total interruption in the delivery of, or ability to deliver, Energy; and

(b) in the case of the Transmission System, a partial or total interruption in the transmission of, or ability to transmit, Energy from the Seller's Plant.

71. "**Party**" means: (i) the Buyer and its successors and permitted assigns; or (ii) the Seller and its successors and permitted assigns, and "Parties" means both the Buyer and the Seller and their respective successors and permitted assigns, provided that the Distribution Authority shall be deemed not to be a "Party", whether or not owned or operated by British Columbia Hydro and Power Authority.

72. "**Peak Demand Months**" means January, February, March, November and December.

73. "**Performance Security**" means a letter of credit in the form specified in section 13.4 in an amount equal to:

(a) prior to the first anniversary of COD, $60,000/MW multiplied by the Plant Capacity; or

(b) from and after the first anniversary of COD, $40,000/MW multiplied by the total of the Monthly Firm Energy Amounts set out in Appendix 2 divided by 8760.

74. "**Permits**" means permits, certificates, licences, and other approvals required for the design, construction, ownership, operation and maintenance of the Seller's Plant and the delivery of Eligible Energy at the POI, including all Material Permits.

75. "**Person**" means an individual, body corporate, firm, partnership, joint venture, trust, legal representative or other legal entity.

76. "**Planned Islanding Capability**" means the ability of a generator to electrically energize, in a safe, controlled and reliable manner, a portion of the Transmission System or Distribution System, including loads, that is separated from the rest of the Transmission System or Distribution System.

77. "**Planned Outage**" means an Outage for purposes of inspection and/or general overhaul of equipment in the Seller's Plant.

78. "**Plant Capacity**" means the electrical capacity of the Seller's Plant expressed in MW, determined as the nameplate capacity if expressed in MW, or as the nameplate capacity if expressed in MVA multiplied by a power factor of 0.95, as set out in Appendix 5, as amended in accordance with section 4.2.

79. "**POI**" or "**Point of Interconnection**" means the point at which the Seller's Plant interconnects with the Transmission System as more particularly defined in the Interconnection Agreement.

80. "**PPT**" means Pacific Prevailing Time, which means Pacific Daylight Time or Pacific Standard Time as applicable.

81. "**Pre-COD Energy**" means that amount of Metered Energy delivered by the Seller at the POI prior to COD including Test Energy, but excluding:

(a) any portion of the Metered Energy that at any time exceeds 120% of the Plant Capacity; and

(b) that portion of the Metered Energy that is sold to third parties in accordance with section 7.1.

82. "**Present Value Rate**" has the meaning given in subsection 15.5(k).

83. "**Prime Rate**" means the floating prime interest rate announced from time to time by the main branch of Bank of Montreal in Vancouver, or any successor thereto, expressed as an annual rate, as the reference rate it will use to determine rates of interest payable on Canadian dollar commercial loans made in Canada.

84. "**Proceeding**" has the meaning given in section 1.5.

85. "**Project**" means the financing, design, engineering, procurement, construction, commissioning, operation and maintenance of the Seller's Plant.

86. "**Project Assets**" means the Seller's Plant and all rights, property, assets, equipment, materials and contracts required to design, engineer, procure, construct, commission, operate and maintain the Seller's Plant, whether real or personal and whether tangible or intangible, including equipment and other warranties, Permits, supply and other contracts, the goodwill in and right to use the name by which the Seller's Plant is commonly known, the books, records and accounts with respect to the Seller's Plant, and all land tenure and land tenure agreements with respect to the Seller's Plant.

87. "**PST**" means British Columbia provincial social service or sales taxes and similar or replacement assessments, if any.

88. "**Seller**" means the Party so identified on page one of this EPA, and its successors and permitted assigns.

89. "**Seller Termination Event**" means:

(a) the Buyer is Bankrupt or Insolvent;

(b) except where an amount has been disputed in the manner specified in subsection 9.1(b), an amount due and payable by the Buyer to the Seller under this EPA remains unpaid for 15 days after its due date and such default has not been cured within 15 days after the Seller has given notice of the default to the Buyer; or

(c) the Buyer is in material default of any of its covenants, representations and warranties or other obligations under this EPA (other than as set out above), and such default has not been cured within 30 days after the Seller has given notice of the default to the Buyer or, if the default cannot be cured within that 30 day period, the Buyer fails to demonstrate to the reasonable satisfaction of the Seller that the Buyer is working diligently and expeditiously to cure the default or the default is not cured within a further reasonable period of time.

90. **"Seller's Plant"** means the Seller's plant described in Appendix 5 and all facilities and equipment required to construct, operate and maintain the plant described in Appendix 5 and to interconnect that plant to the Transmission System.

91. "**Station Service**" means electricity required to service the Seller's Plant, including electricity required for fuel processing.

92. "**Tender**" means the Tender submitted by the Seller pursuant to the CFT.

93. "**Term**" has the meaning given in section 2.1.

94. "**Termination Payment**" means the amount payable by the Seller to the Buyer or the amount payable by the Buyer to the Seller pursuant to section 15.4 or section 15.5, as the case may be.

95. "**Test Energy**" means Metered Energy delivered at the POI during any successful test pursuant to subsection 5.2(b), but excluding all Metered Energy that at any time exceeds 120% of the Plant Capacity.

96. "**Transmission Authority**" means the British Columbia Transmission Corporation or any successor thereto.

97. "**Transmission System**" means the transmission, substation, protection, control and communication facilities: (i) owned by the Buyer or by the Transmission Authority; and (ii) operated by the Transmission Authority in British Columbia, and includes all additions and modifications thereto and repairs or replacements thereof.

98. "**UCA**" means the *Utilities Commission Act* (British Columbia).

99. "**WECC**" means the Western Electricity Coordinating Council or any successor organization of which the Buyer is a member.

APPENDIX 2

ENERGY PROFILE

[To be inserted from the Seller's Tender]

*For leap years, the Monthly Firm Energy Amount for the month of February will be multiplied by 29/28.

[Note to Bidders: For Bidders that elect to tender an Hourly Firm Energy Profile, the table set out in Section 11 of the CFT in the bullet titled "Energy Profile" will be inserted in Appendix 2 as Part 2 of Appendix 2.]

APPENDIX 3

ENERGY PRICE

1. Definitions and Interpretation

1.1 **Definitions** - In this Appendix 3 or elsewhere in the EPA, the following words and expressions have the following meanings:

(a) "**BPP**" or "**Bid Price Percentage**" means __BP#5___%, which is the percentage of the Initial Period Bid Price and the Remainder Period Bid Price that is subject to escalation pursuant to section 3.3 of this Appendix.

(b) "**CPI**" means the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada, adjusted or replaced in accordance with subsection 1.2(d) of this Appendix.

(c) "**Discount Amount**" means $8.00/MWh.

(d) "**Escalated Bid Price**" means:

(i) for the period from COD to the hour ending at 24:00 PPT on the day immediately prior to the first day of the month following the _BP#2____ anniversary of COD, the Initial Period Bid Price, as adjusted pursuant to section 3.3 of this Appendix; and

(ii) for the period from the hour commencing at 00:00 PPT on the first day of the month following the __BP#2___ anniversary of COD for the remainder of the Term, the Remainder Period Bid Price, as adjusted pursuant to section 3.3 of this Appendix.

[Note to Bidders: If there is only one Bid Price for the Term, the above section will be revised to read ""Escalated Bid Price" means the Bid Price $__BP#4_/MWh as adjusted pursuant to section 3.3 of this Appendix."]

(e) "**Escalated Discount Amount**" means the Discount Amount as adjusted pursuant to section 3.3 of this Appendix.

(f) "**Firm Energy**" means in each month of the Term after COD, all Eligible Energy in that month not exceeding the Monthly Firm Energy Amount for that month, but excluding any Eligible Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4 and all such Eligible Energy will be considered Non-Firm Energy.

(g) "**Firm Energy Price**" means the Escalated Bid Price as adjusted pursuant to section 3.4 of this Appendix.

(h) "**HLH**" or "**Heavy Load Hours**" means the hours commencing at 06:00 PPT and ending at 22:00 PPT Monday through Saturday inclusive but excluding British Columbia statutory holidays.

(i) "**Initial Period Bid Price**" means $____BP#3_____/ MWh.

[Note to Bidders: If there is only one Bid Price for the Term, the above definition will be revised to read "Bid Price means $ BP#4 /MWh".]

(j) "**LLH**" or "**Light Load Hours**" means all hours other than Heavy Load Hours.

(k) "**Mid-C**" means the Mid-Columbia electricity region.

(l) "**Non-Firm Energy**" means in each month of the Term after COD all Eligible Energy in that month in excess of the Monthly Firm Energy Amount for that month and all Eligible Energy deemed to be Non-Firm Energy pursuant to subsection 1.1(f) of this Appendix.

(m) "**Non-Firm Energy Discount**" means the Escalated Discount Amount as adjusted pursuant to section 3.4 of this Appendix.

(n) "**Off-Peak Index**" means the Dow Jones Mid-C daily firm Off-Peak Index.

(o) "**Remainder Period Bid Price**" means $__BP#3_ / MWh.

[Note to Bidders: If there is only one Bid Price for the Term, the above definition will be deleted.]

(p) "**Tier 1 Non-Firm Energy**" means in each month during the Term after COD all Non-Firm Energy not exceeding an amount equal to the Monthly Firm Energy Amount for the month.

(q) "**Tier 1 Non-Firm Energy Price**" means the Firm Energy Price minus the Non-Firm Energy Discount.

(r) "**Tier 2 Non-Firm Energy**" means in each month during the Term after COD all Non-Firm Energy in excess of the Tier 1 Non-Firm Energy for that month.

(s) "**Tier 2 Non-Firm Energy Price**" means the lesser of:

(i) the Tier 1 Non-Firm Energy Price; and

(ii) an amount equal to 70% of the average of the daily non-firm Mid-C Off-Peak Index prices in the applicable month. Amounts quoted in U.S. dollars will be converted to Canadian dollars using the average of the Bank of Canada daily "noon rates" for that month.

1.2 **Interpretation -** All payments will be calculated applying the following principles:

(a) all payment calculations will be rounded to the nearest cent;

(b) Energy will be expressed in MWh rounded to two decimal places;

(c) any escalators or percentages will be expressed as a percentage and will be rounded to four decimal places (i.e. 0.0000%); and

(d) if Statistics Canada (or the then recognized statistical branch of the Canadian Government):

(i) computes, at any time after the Effective Date, the CPI on a basis different to that employed at the Effective Date, then the CPI will be converted using the appropriate formula recommended by Statistics Canada (or the then recognized statistical branch of the Canadian Government);

(ii) at any time ceases to publish or provide the CPI, then the provisions of section 1.9 of this EPA will apply;

(iii) has not published the CPI for a relevant period at the time the Seller is required to provide the Buyer with an invoice, the Seller shall prepare the invoice based on the CPI in effect at the time the invoice is issued and when the CPI for the relevant period is published, the Seller shall recalculate the invoice amounts in the next succeeding invoice and shall include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation; or

(iv) recalculates the CPI within 36 months after an invoice affected by that CPI calculation has been issued, then the Seller shall recalculate the invoice amounts for the relevant period in the next succeeding invoice and shall include a credit or debit, without interest, in the next succeeding invoice based on the results of the recalculation.

2. Pre-COD Energy

2.1 No price is payable by the Buyer for Energy, if any, delivered to the Buyer before COD, except as set out in section 2.2 of this Appendix.

2.2 The price payable by the Buyer for Test Energy in respect of which the Seller has not given a notice under section 7.1 is $25.00/MWh. If the Seller's Plant does not satisfy the requirements of section 5.2, no price is payable by the Buyer for any Energy generated during the period specified in subsection 5.2(b).

3. Post-COD Energy

3.1 **Firm Energy** - The price payable by the Buyer for each MWh of Firm Energy is the Firm Energy Price.

3.2 **Non-Firm Energy** - The price payable by the Buyer for each MWh of Tier 1 Non-Firm Energy is the Tier 1 Non-Firm Energy Price. The price payable by the Buyer for each MWh of Tier 2 Non-Firm Energy is the Tier 2 Non-Firm Energy Price.

3.3 **CPI Adjustment** - The Initial Period Bid Price ("**IPBP**"), the Remainder Period Bid Price ("**RPBP**") and the Discount Amount ("**DA**") will be adjusted effective as of January 1 in each year after the Effective Date in accordance with the following applicable formula:

$$IPBP_n = IPBP_{January\ 1\ 2006} * [(BPP * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}) + (1 - BPP)]$$

$$RPBP_n = RPBP_{January\ 1\ 2006} * [(BPP * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}) + (1 - BPP)]$$

$$DA_n = DA_{January\ 1\ 2006} * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$$

Where:

n = the year for which the relevant calculation is being conducted

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately prior to the year for which the relevant calculation is being conducted.

3.4 **Delivery Time Adjustment** - For each hour during the Term, the Escalated Bid Price and the Escalated Discount Amount will be adjusted to an amount (expressed in $/MWh) equal to the percentage of the Escalated Bid Price or the Escalated Discount Amount, as applicable, expressed in the following table:

Month	Escalated Bid Price Adjustment		Escalated Discount Amount Adjustment	
	HLH	LLH	HLH	LLH
January	113%	97%	88%	103%
February	109%	102%	92%	98%
March	105%	100%	95%	100%
April	103%	88%	97%	114%
May	104%	73%	96%	137%
June	104%	71%	96%	141%
July	104%	77%	96%	130%
August	104%	97%	96%	103%
September	105%	98%	95%	102%
October	103%	89%	97%	112%
November	106%	104%	94%	96%
December	117%	101%	85%	99%

3.5 **Calculation of Firm and Non-Firm Energy Amounts** - If in any month after COD the Eligible Energy for the month exceeds the Monthly Firm Energy Amount for that month, the amount of Firm Energy and Non-Firm Energy delivered during Heavy Load Hours is determined by multiplying the total Firm Energy or Non-Firm Energy amount for that month, as applicable, by the proportion of total Eligible Energy delivered during Heavy Load Hours in that month. The remainder of the Energy in each case will be deemed to have been delivered in Light Load Hours. The following provides an illustration of the application of this section:

	HLH	LLH	Total
Tendered Firm Energy	N/A	N/A	20
Total Eligible Energy delivered *as a % of total*	30 *60%*	20 *40%*	50 *100%*
Firm Energy delivered	12	8	20
Tier 1 Non-Firm Energy delivered	12	8	20
Tier 2 Non-Firm Energy delivered	6	4	10

3.6 **Third Person Sales** - Where the Seller has sold Energy to a third Person in accordance with section 7.5, there shall be deducted from the amount otherwise payable by the Buyer to the Seller in respect of the Energy that is deemed to be Eligible Energy pursuant to section 7.9 an amount equal to any revenue received by the Seller from the third Person for that Energy.

4. Property Tax Flow Through

In each year during the Term after COD, provided that the taxes payable in respect of the Seller's Plant in that year exceed the taxes payable in respect of the Seller's Plant during the year in which COD occurred determined in accordance with the following formula (where the definitions applicable to such formula have the meaning given below):

$$[(TRl_n * AVl_n) + (TRi_n * AVi_n)] > [(TRl_{COD} * AVl_{COD}) + (TRi_{COD} * AVi_{COD})],$$

then, the Buyer shall pay the Seller an amount determined in accordance with the following formula:

Payment Amount = (the greater of (i) zero and (ii) the amount determined in accordance with the following formula):

$$\{[(TRl_n - TRl_{COD}) * AVl_n] + [(TRi_n - TRi_{COD}) * AVi_n]\} * 0.5$$

Where:

TRl	=	Tax rates for the land on which the Seller's Plant is located
TRi	=	Tax rates for the improvements
AVl	=	Assessed value of the land on which the Seller's Plant is located
AVi	=	Assessed value of the improvements
n	=	the year in which the tax invoice is received by the Seller

"tax" means any ad valorem tax imposed by any Governmental Authority with respect to the Seller's Plant, including the associated land, as shown on the annual property tax notice for the Seller's Plant.

"improvements" means those improvements forming part of the Seller's Plant at COD.

Notwithstanding the foregoing, the Buyer will only be required to pay a portion of the amount determined in accordance with the foregoing formula based on the portion of the year following COD or the portion of the year prior to termination, as applicable. In addition, the amount payable by the Buyer will be reduced on a proportionate basis for each day in which the Seller does not deliver Eligible Energy to the Buyer, except where the Seller is excused from its delivery obligation under subsection 7.8(a).

The Seller shall have the burden of proving which improvements formed part of the Seller's Plant at COD. In each year during the Term after COD, within 60 days after receipt of the tax statement for the Seller's Plant, the Seller shall provide an invoice to the Buyer for any amount owing by the Buyer to the Seller pursuant to this section, together with all information and documents reasonably required to support the invoice. The Buyer shall pay any amount owing by the Buyer to the Seller under this section within 60 days after receipt from the Seller of an invoice in accordance with this section.

5. No Further Payment

5.1 The amounts payable by the Buyer as specified in this Appendix 3 are the full and complete payment and consideration payable by the Buyer for all Eligible Energy under this EPA.

APPENDIX 4

COD CERTIFICATE

_____ PROJECT

TO: British Columbia Hydro and Power Authority (the "**Buyer**")

RE: Electricity Purchase Agreement ("**EPA**") made as of ●, 2006 between the Buyer and ● (the "**Seller**") for _____ Project

I, *[name of senior officer]*, in my capacity as *[title of senior officer]* of the Seller, and not in my personal capacity, certify on behalf of the Seller that:

1. **Defined Terms** - Words and phrases having initial capitalized letters in this Certificate have the meanings given in the EPA.

2. **COD Requirements** - The Seller has satisfied the requirements for COD as set out in section 5.2 of the EPA. Attached to this Certificate is all evidence required to demonstrate that the Seller has satisfied all such requirements.

3. **No Material Default** - No event which constitutes a Buyer Termination Event under subsection (a) or (e) of the definition of "Buyer Termination Event" in Appendix 1 to the EPA has occurred. The Seller has obtained all Material Permits and is not in material default under any Material Permit (and all Material Permits are in full force and effect), any tenure agreement for the site on which the Seller's Plant is located, the Interconnection Agreement or the Facilities Agreement.

Dated this _____ day of _____, 200____.

_____

[name of senior officer]

[title of senior officer]

[Attach to the Certificate in tabbed format all documents and evidence required under section 5.2 of the EPA. Where documents have previously been provided to the Buyer, so indicate and attach a copy of the letter transmitting such documents to the Buyer.]

APPENDIX 5

SELLER'S PLANT DESCRIPTION

[Note to Bidders: To be inserted from the Seller's Tender - See CFT Form #2]

APPENDIX 6

SAMPLE FORM STANDBY LETTER OF CREDIT

[Issuing Bank Name & Address]

Date of Issue: [Date]

Irrevocable Standby Letter of Credit

[*Number*]

Applicant:

[*Seller Name and Address]*

Beneficiary:

British Columbia Hydro and Power Authority

At the request and for the account of the Applicant, we hereby establish in favour of the Beneficiary our irrevocable standby Letter Of Credit No. ([*Number*]) (hereinafter called the "**Letter of Credit**") for an amount not exceeding [*Currency and Amount both in letters and numbers*].

We, [*Bank Name and Address*] hereby unconditionally and irrevocably undertake and bind ourselves, and our successors and assigns, to pay you immediately, the sum, which you claim upon receipt of the following documents:

(1) your signed written demand specifying the amount claimed (not exceeding [*Dollar Amount*]), and certifying that such amount is due to you by the Applicant under the terms of an Electricity Purchase Agreement between you and the Applicant made as of [*Date*]; and

(2) this original Letter of Credit must be presented with your demand for payment for endorsement purposes.

Partial drawings are allowed. The amount of this Letter of Credit shall be automatically reduced by the amount of any drawing paid hereunder.

This Letter of Credit takes effect from the date of issue set forth above, and shall remain valid until [ ] However, it is a condition of this Letter of Credit that it will be automatically extended without notice for a further one year period from the present or any future expiry date unless at least ninety (90) days prior to such expiry date we notify you in writing by courier or registered mail at your address above that we elect not to consider this Letter of Credit to be extended for any additional period.

This Letter of Credit is subject to the Uniform Customs and Practice for Documentary Credits (1993 Revision), International Chamber of Commerce, (Publication No. 500). This Letter of Credit is governed by the laws applicable in the Province of British Columbia. The parties hereby irrevocably attorn to the non-exclusive jurisdiction of the courts of British Columbia. The number of this Letter of Credit must be quoted on all documents required hereby. Notwithstanding Article 17 of said publication, if this Letter of

Credit expires during an interruption of business as described in Article 17, we agree to effect payment if this Letter of Credit is drawn within 15 days after resumption of normal business.

_____	_____
Authorized Signing Officer	Authorized Signing Officer
[Bank Name]	[Bank Name]

APPENDIX 7

SAMPLE FORM LENDER CONSENT AGREEMENT

(See section 16.3)

THIS AGREEMENT is made as of _____ ____, 200_,

AMONG:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a corporation continued under the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212, having its head office at 333 Dunsmuir Street, Vancouver, British Columbia, V6B 5R3,

(the "**Buyer**")

AND:

[COMPANY], a company under the laws of _____having an address at _____,

(the **"Company")**

AND:

[LENDER], a _____ under the laws of _____having an address at _____,

(the "**Lender**").

WHEREAS:

A. The Buyer and the Company entered into an Electricity Purchase Agreement made as of _____ (as amended from time to time, the "EPA");

B. The Company has obtained certain credit facilities (the "Credit") from the Lender for the purposes of financing the design, construction, operation and maintenance of the Seller's Plant (as defined in the EPA);

C. To secure the due payment of all principal, interest (including interest on overdue interest), premium (if any) and other amounts payable in respect of the Credit and the due performance of all other obligations of the Company under the Credit, the Company has granted certain security to and in favour of the Lender, including an assignment of the right, title and interest of the Company under the EPA and security on the Seller's Plant (collectively, the "Lender Security"); and

D. The Lender has requested the Buyer to enter into this Agreement confirming certain matters.

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and of the sum of $10 and other good and valuable consideration now paid by each of the Company and the Lender

to the Buyer (the receipt and sufficiency of which are hereby acknowledged by the Buyer), the parties covenant and agree that:

1. Additional Definitions: In this Agreement, including the recitals:

(a) "**Assumption Notice**" means a notice given by the Lender to the Buyer pursuant to subsection 6.1(a) of this Agreement;

(b) "**Default or Termination Notice**" means a notice given to the Company by the Buyer under the EPA that, with or without the lapse of time, entitles, or will entitle, the Buyer to terminate the EPA, subject to rights, if any, of the Company to cure the default or other circumstance in respect of which the notice is given;

(c) "**Receiver**" means a receiver, manager or receiver-manager appointed or designated by, or on the initiative of, the Lender; and

(d) words and phrases defined in the EPA, and not otherwise defined herein, when used herein have the meanings given in the EPA.

2. **EPA Amendments**: The Buyer and the Company acknowledge and agree that the EPA is in full force and effect, and that the EPA, as originally executed, has been amended only by the documents attached hereto as Schedule A.

3. **Buyer Confirmations Concerning the EPA**: The Buyer confirms to the Lender that:

(a) the EPA has been duly authorized, executed and delivered by the Buyer;

(b) the Buyer has not received any notice of assignment by the Company of all or any part of their right, title and interest in and to the EPA, except to the Lender;

(c) the Buyer has not given any Default or Termination Notice;

(d) the Buyer is not aware of any default or other circumstance that would entitle the Buyer to give a Default or Termination Notice, provided however that the Buyer has not undertaken any investigation or due diligence in respect of this confirmation; and

(e) the Buyer shall not enter into any agreement with the Company to materially amend the EPA, or enter into any agreement with the Company to terminate the EPA, without giving the Lender not less than 30 days' prior written notice.

4. **Assignment of EPA to Lender**:

4.1 *Buyer Acknowledgement:* The Buyer acknowledges receipt of notice of, and consents to, the assignment by the Company to the Lender of all the right, title and interest of the Company in and to the EPA made pursuant to and in accordance with the Lender Security.

4.2 *Lender Acknowledgement:* The Lender acknowledges that:

(a) it has received a copy of the EPA; and

(b) the assignment by the Company to the Lender of the EPA pursuant to the Lender Security is subject in all respects to the terms and conditions of the EPA and this Agreement.

4.3 *Confidentiality:* The Lender covenants and agrees with the Buyer to be bound by the provisions of section 20.8 of the EPA regarding confidentiality, as if an original signatory thereto.

4.4 *Company Representation:* The Company represents and warrants to the Buyer that the Lender is the only person, other than the Buyer, to whom it has granted a security interest in the EPA or the Seller's Plant.

5. **EPA Notices**: The Buyer covenants and agrees with the Lender that, except as hereinafter otherwise permitted, the Buyer:

(a) shall give the Lender a copy of any Default or Termination Notice concurrently with, or promptly after, any such notice is given to the Company;

(b) shall not exercise any right it may have to terminate the EPA or any right pursuant to Article 14 of the EPA until the later of: (i) the date that is 45 days after the date on which the Buyer delivered to the Lender a copy of the Default or Termination Notice entitling the Buyer to terminate or exercise any right pursuant to Article 14 of the EPA; and (ii) the date on which the Buyer is entitled to terminate or exercise any right pursuant to Article 14 of the EPA;

(c) shall not, provided that there is no other Buyer Termination Event under the EPA, terminate the EPA based on the Bankruptcy or Insolvency of the Seller if the Lender is promptly and diligently prosecuting to completion enforcement proceedings under the Lender Security until 30 days after the expiry of any court ordered period restricting the termination of the EPA; and

(d) shall not exercise any right it may have under section 9.5 of the EPA to deduct any amounts owing by the Seller to the Buyer under the EPA from amounts owing by the Buyer to the Seller under the EPA until the date that is 15 days after the date the Buyer provides the Lender with a copy of the notice delivered by the Buyer to the Seller under section 9.5 of the EPA.

Nothing in this Agreement prevents or restricts: (i) the exercise by the Buyer of any other right or remedy that it may be entitled to exercise under or in relation to the EPA; or (ii) the right of the Lender to cure, or cause the cure of, any default of the Company under the EPA that would be curable by the Company, whether or not an Assumption Notice is given.

6. **Realization by Lender**:

6.1 *Assumption Notice and/or Sale:* If the Company has defaulted under the Credit or the Lender Security and the Lender has elected to take possession of the Seller's Plant, either by a Receiver or in any other way, pursuant to the Security, the Lender shall either:

(a) give the Buyer written notice (an "**Assumption Notice**") stating that the Lender is assuming the EPA, whereupon:

(i) the Lender shall be entitled to all the rights and benefits, and shall have assumed, and shall perform and discharge, all the obligations and liabilities, of the

Company under the EPA, and the Lender shall be a party to, and bound by, the EPA as if an original signatory thereto in the place and stead of the Company;

(ii) notwithstanding subparagraph (i), the Lender shall not be liable to the Buyer for defaults of the Company occurring before the Assumption Notice is given, except to the extent that such defaults continue thereafter; provided however that the Buyer may at any time before or after such notice is given exercise any rights of set-off in respect of any such prior default under or in relation to the EPA which the Buyer would otherwise be entitled to exercise; or

(b) give written notice to the Buyer that the Lender wishes to cause the Company to assign all of the Company's right, title and interest in and to the EPA and the Seller's Plant to a third person or persons, subject however to the Company and the assignee complying with all provisions of the EPA relative to such assignment.

The Buyer agrees that if the Lender enters the Seller's Plant for the purpose of viewing or examining the state of repair, condition or operation thereof such shall not constitute taking possession thereof.

6.2 *Lender Liability and Release:* The Lender assumes no liability to the Buyer under the EPA unless and until the Lender gives an Assumption Notice. Thereafter, if the Lender completes an assignment to a third person or persons pursuant to and in accordance with the applicable provisions of the EPA, the Lender shall be released from all liability and obligations of the Company to the Buyer under the EPA accruing from and after completion of that assignment.

6.3 *Company not Released:* Nothing in this Agreement, and neither the giving of an Assumption Notice, nor any assignment pursuant to subsection 6.1(b) of this Agreement releases the Company from its obligations and liabilities to the Buyer under and in relation to the EPA.

6.4 *Receiver Included:* References in this section 6 to the Lender include a Receiver.

7. **Notices**: Any notice required or permitted to be given under this Agreement must be in writing and may be given by personal delivery, or by transmittal by facsimile, addressed to the respective parties as follows:

(a) Buyer at:

British Columbia Hydro and Power Authority
_____
_____
Attention: _____
Facsimile No.: _____

(b) **[Company]** at:

_____
_____
Attention: _____
Facsimile No.: _____

(c) **[Lender]** at:

_____
_____
Attention: _____
Facsimile No.: _____

Notices given by facsimile shall be deemed to be received on the business day next following the date of transmission.

8. **Choice of Law**: This Agreement is governed by British Columbia law, and the laws of Canada applicable therein.

9. **Jurisdiction**: Each party to this Agreement attorns irrevocably and unconditionally to the courts of the Province of British Columbia, and to courts to which appeals therefrom may be taken, in connection with any action, suit or proceeding commenced under or in relation to this Agreement. Notwithstanding the foregoing, the Lender acknowledges that upon an Assumption Notice being given, the Lender will become party to, and bound by, the agreements to arbitrate contained in section 20.7 of the EPA.

10. **Termination**: This Agreement, and all rights and liabilities among the parties hereunder shall terminate upon the full and final discharge of all of the Lender Security. The Lender shall give the Buyer prompt notice of the full and final discharge of all of the Lender Security.

11. **Amendment**: This Agreement may be amended only by an instrument in writing signed by each of the parties hereto.

12. **Enurement**: This Agreement enures to the benefit of, and is binding upon, the parties hereto, and their respective successors and permitted assigns.

13. **Counterparts**: This Agreement may be executed by facsimile and in any number of counterparts, each of which is deemed an original, and all of which together constitute one and the same document.

14. **Effective Date**: This Agreement is not binding upon any party unless and until executed and delivered by all parties, whereupon this Agreement will take effect as of the day first above written.

IN WITNESS WHEREOF each of the parties have duly executed this Agreement as of the day and year first above written.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	**[COMPANY]**
By:_____ (Signature)	By:_____ (Signature)
Name: _____	Name: _____
Title: _____	Title: _____

[LENDER]

By: _____
(Signature)

Name: _____

Title: _____

APPENDIX 8

SAMPLE FORM DEVELOPMENT PROGRESS REPORT

BC Hydro Quarterly Development Report
For the quarter ending: _____ Report Number:_____
Project Name: _____

Tasks:	**Percentage of Completion**					**Comments**
	5%	25%	50%	75%	100%	
Permitting:						
Water Licence ***[Note to Bidders: This section will be expanded in the Awarded EPA to contain a list of Permits relevant to the Bidder's Project based on the information in the Bidder's Project Submission.]***						
Zoning Approval						
Subdivision Approval						
Leave to Construct						
Other Permits						
Financing:						
Construction						
Project Equity						
Long Term Financing						
Project Design:						
Preliminary						
Final						
Interconnection:						
Studies (Please describe the status of each interconnection study)						
Construction						
Major Equipment:						
Ordering						
Delivery						
Installation						
Construction:						
Road						
Powerhouse						
Other						

Key Project Tasks:	Target	Actual
Permitting Complete		
Financing Complete		
Interconnection/Facilities		

Agreements Signed		
Major Equipment Ordered		
Commence Construction		
Begin Commissioning		

COD:

Current Estimate: _____

Prepared by: _____

Submitted by: _____

APPENDIX 9

ADDRESSES FOR DELIVERY OF NOTICES

Subject to subsection 20.4(e), the address for each of the Parties for notices is as follows:

Buyer: BC Hydro	Seller:
All Notices (Except as set out below)	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	To: Address: Email:
Development Reports	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	N/A
Planned Outages, Operating Plans, Notice of Outages, Energy Schedules	
To: Resource Coordinator, Plant Operations Group, Generation Address: 6911 Southpoint Drive, E15 Burnaby , B. C. V3N 4X8 Attention: (name to be inserted in Awarded EPA) Email: (to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:
GHG Compliance Reports	
To: Triple Bottom Line Strategy Address: 333 Dunsmuir Street, 9th floor Vancouver, B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: (to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:

Buyer: BC Hydro	Seller:
Invoices and Statements	
To: IPP Invoicing Address: 333 Dunsmuir Street, 16th floor Vancouver, B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Invoicing@bchydro.com	To: Address: Email:
Performance Security	
To: Distribution Line of Business, Finance Address: 6911 Southpoint Drive, E16 Burnaby, B.C. V3N 4X8 Attention: (name to be inserted in Awarded EPA) Copy to: Contract Management, as per all Notices address	To: Address: Email:
Insurance	
To: Manager, Contract Management Address: 333 Dunsmuir Street, 10th floor Vancouver B.C. V6B 5R3 Attention: (name to be inserted in Awarded EPA) Email: IPP.Contract@bchydro.com	To: Address: Email:

If the Seller is a joint venture, general partnership or limited partnership, a notice given in accordance with the foregoing provisions is deemed to have been given to the Seller and to each joint venturer and/or partner as applicable.

APPENDIX 10

SPECIAL TERMS AND CONDITIONS

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PART A - HOURLY FIRM PROJECTS

This Part applies to Sellers that submitted an Hourly Firm Energy Profile in the CFT process.

1. Subsection 5.2(b) is deleted and replaced with the following:

   (b) the Seller's Plant has generated Energy in compliance with all Material Permits for 72 continuous hours in an amount not less than the greater of: (i) 95% of the Hourly Firm Energy Amount for each such hour; and (ii) 20% of the Plant Capacity multiplied by 1 hour;

2. Section 5.6 is amended by deleting the words "Monthly Firm Energy Amount" wherever those words appear in that section and replacing them with "Hourly Firm Energy Amount".

3. Subsection 6.4(a) is deleted and replaced with the following:

   "(a) ensure that no Planned Outage occurs during the Peak Demand Months except with the consent of the Buyer, which consent will not be unreasonably withheld where the Seller is required to conduct a Planned Outage during Peak Demand Months by reason of Law, Permits or contracts and where, in the case of a contractual requirement, the Seller has used commercially reasonable efforts to avoid inclusion of such requirement in the contract. Where the Seller is authorized under this section to conduct a Planned Outage or Planned Outages during Peak Demand Months, the total number of hours of such Planned Outages in any November to March period shall not exceed 180;"

4. Subsection 6.6(f) is deleted and replaced with the following:

   "(f) **Energy Schedules** - After COD on each Thursday by 12:00 PPT, the Seller shall deliver to the Buyer a schedule of the expected deliveries of Eligible Energy in each hour of each day for the next succeeding week commencing at 00:00 PPT on Monday, provided that such schedules are provided for planning purposes only and do not constitute a guarantee by the Seller that Energy will be delivered in accordance with the schedules and do not limit the amount of Energy the Seller may deliver during the periods covered by the schedules. The Seller shall deliver a revised schedule to the Buyer forthwith upon becoming aware of any expected material change in a filed Energy schedule."

5. Section 7.2 is deleted and replaced with the following:

   "7.2 **Modification to Hourly Firm Energy Amount** - The Seller may at any time prior to the first anniversary of COD, give notice to the Buyer that the Seller elects to increase or decrease any Hourly Firm Energy Amount to take effect on the first day of the month immediately following the giving of such notice, provided that the net change in the annual total of the Monthly Firm Energy Amounts resulting from such increases or decreases in any Hourly Firm Energy Amount does not exceed 10%. Upon receipt of such notice, the Buyer and the Seller shall execute an amendment to this EPA to amend Appendix 2 in accordance with the Seller's notice, provided that:

      (a) any such increase or decrease in any of the Hourly Firm Energy Amounts does not result in the total of the Monthly Firm Energy Amounts for the period from April to July, inclusive, exceeding one-third of the annual total of the Monthly Firm Energy Amounts;

(b) any such increase or decrease in the Hourly Firm Energy Amounts does not result in any Hourly Firm Energy Amount exceeding the Plant Capacity multiplied by 1 hour; and

(c) the provisions of subsections 4.2(a) and (b) apply to any such increase or decrease in the Hourly Firm Energy Amounts, *mutatis* mutandis; and

(d) the Seller may give only one notice under this section.

6. Section 7.3 is deleted and replaced with the following:

"7.3 **Post-COD Sale of Energy** - Subject to subsection 7.8(a), in each hour during the Term after COD, the Seller shall sell and deliver to the Buyer at the POI, the Hourly Firm Energy Amount for the applicable hour."

7. Section 7.4 is amended by deleting the word "month" and replacing it with "hour".

8. Section 7.9 is amended by:

(a) deleting the word "month" wherever it appears in that section, except in subsection 7.9(a)(ii), and replacing it with "hour"; and

(b) deleting the words "in that month" in subsection 7.9(a)(ii) and replacing them with "in the month for which the amount of Eligible Energy is being calculated"; and

(c) deleting the balance of the section after subsection (b) and replacing it with the following:

"then, notwithstanding that the Buyer is excused under subsection 7.8(b) from its obligations under section 7.4, in the case of an event described in subsection 7.9(a), that portion of the applicable Hourly Firm Energy Amount that could have been generated and delivered to the POI in each hour after the 24 hours has elapsed but for the occurrence of the event described in subsection 7.9(a), will be deemed to be Eligible Energy, and in the case of an event described in subsection 7.9(b), the amount of Energy, not exceeding the Plant Capacity, that could have been generated and delivered to the POI but for the occurrence of the event described in subsection 7.9(b) will be deemed to be Eligible Energy. The amount of Energy that could have been generated and delivered to the POI during an event described in subsection 7.9(a) or (b), will be determined based on the Seller's Energy schedule for each hour in the applicable period, meter readings with respect to the Energy Source, if applicable, readings of the Metering Equipment before and after the occurrence of the event described in subsection 7.9(a) or (b) and other available information. There will be no deemed Eligible Energy during any period specified as a Planned Outage period in a notice delivered by the Seller under section 6.4. For greater certainty, the provisions of section 7.9 will not apply during any period when either Party is excused, in accordance with Article 11, from its obligation to deliver, or to accept delivery of, Energy as a result of a Force Majeure.

9. Section 12.2 is deleted and replaced with the following:

"12.2 **Delivery Shortfalls** - If in any hour after the first anniversary of COD, the Delivered Eligible Energy in that hour is less than 90% of the Hourly Firm Energy Amount for that hour, the Seller shall pay LDs to the Buyer calculated as follows:

LD Amount = LD Factor * ((0.9 * Hourly Firm Energy Amount) – Delivered Eligible Energy)

Where:

(a) the Hourly Firm Energy Amount is the amount set out in Appendix 2 for the relevant hour less an amount equal to the Hourly Firm Energy Amount divided by 60 for each minute in which the Seller is excused under subsection 7.8(a) from the obligation to deliver Energy;

(b) "Delivered Eligible Energy" means in each hour the amount of Eligible Energy determined pursuant to subsection (a) of the definition of "Eligible Energy" for that hour, but excluding any Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4;

(c) LD Factor = the greater of: (i) zero and (ii) A-[(FEP/(1-L))+FEPA]

Where:

(i) A = the lesser of:

(I) the LD Cap; and

(II) the Mid-C Index;

(ii) L = _____%;

(iii) FEP = the Firm Energy Price for the hour in which the delivery shortfall occurred;

(iv) FEPA (Firm Energy Price Adjuster)$_n$ = $____/MWh * CPI$_{\text{January 1 n}}$/CPI $_{\text{January 1 2006}}$

Where:

n = the year for which the Firm Energy Price Adjuster is being calculated

CPI $_{\text{January 1 n}}$ = the CPI for December in the year immediately preceding the year for which the Firm Energy Price Adjuster is being calculated;

[Note to Bidders – L will be the greater of (i) zero and (ii) an amount determined from energy loss information used in the CFT evaluation. FEPA will be the sum of the following: -3.00 if the Green Attributes are transferred to BC Hydro; -3.00 to reflect the fact that the Bidder tendered an Hourly Firm Energy Profile; and X if GHG emission offset obligations are transferred to BC Hydro where "X" is the amount determined from the GHG Adjustment Table (CFT Reference Document), based on the Bidder's tendered Guaranteed GHG Intensity]

(v) "Mid-C" means the mid-Columbia electricity region;

(vi) "Mid C Index" means the Dow Jones Mid-C daily firm On-Peak Index, the Dow Jones Mid-C daily firm Off-Peak Index or, on NERC holidays only, the Dow Jones Mid-C 24 hour firm Sunday and NERC Holidays Index as applicable to the hour in which the delivery shortfall occurred. Amounts quoted in U.S. dollars

will be converted to Canadian dollars using the Bank of Canada daily "noon rate" for the day in which the delivery shortfall occurred;

(vii) "LD Cap" means $100/MWh adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

$LD\ Cap_n = \$100/MWH * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$, as further adjusted to an amount (expressed in $/MWh) equal to the amount determined in accordance with the foregoing calculation multiplied by the percentage of the Escalated Bid Price adjustment applicable to the month and hour in which the delivery shortfall occurred as set out in the table in section 3.4 of Appendix 3

Where:

n = the year for which the escalated LD Cap is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately preceding the year for which the escalated LD Cap is being calculated.

Any LDs owing by the Seller to the Buyer pursuant to this section 12.2 shall be payable on 15th day of the month following the month in which the delivery shortfall occurred."

10. Section 12.3 is amended by deleting the word "Monthly" and replacing it with "Hourly".

11. Subsections 15.4(a) and 15.5(a) are amended by deleting the words "set out in Appendix 2" and by inserting the word "annual" before the words "Monthly Firm Energy Amounts" in both sections.

12. Subsection (e) in the definition of "**Buyer Termination Event**" in Appendix 1 is amended by deleting the word "Monthly" and replacing it with "Hourly".

13. The definition of "**Eligible Energy**" in Appendix 1 is amended by deleting the word "month" and replacing it with "hour".

14. The following definition is added to Appendix 1:

"**Hourly Firm Energy Amount**" means for each hour after COD, the amount of Energy the Seller is required to deliver in that hour as set out in Appendix 2."

15. The definition of "**Monthly Firm Energy Amount**" in Appendix 1 is deleted and replaced with the following:

"**Monthly Firm Energy Amount**" means for each month after COD the sum of the Hourly Firm Energy Amounts for that month calculated based on the number of hours for that month set out in Part 2 of Appendix 2.

16. The definition of **"Monthly Firm Energy Delivery Rate"** is deleted from Appendix 1.

17. The definition of "**Performance Security**" in Appendix 1 is amended by deleting the words "set out in Appendix 2", and by inserting the word "annual" prior to the words "Monthly Firm Energy Amounts".

18. The note with respect to leap years at the bottom of Appendix 2 is deleted.

19. The definition of "**Firm Energy**" in section 1.1 of Appendix 3 is deleted and replaced with the following:

"**Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour not exceeding the Hourly Firm Energy Amount for that hour, but excluding any Eligible Energy delivered after the start time and prior to the end time for an Authorized Planned Outage as set out in the notice with respect to the Authorized Planned Outage under section 6.4 and all such Eligible Energy will be considered Non-Firm Energy.

20. The definition of "**Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

"**Non-Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour in excess of the Hourly Firm Energy Amount for that hour and all Eligible Energy deemed to be Non-Firm Energy pursuant to subsection 1.1(f) of this Appendix.

21. The definition of "**Tier 1 Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

"**Tier 1 Non-Firm Energy**" means in each hour of the Term after COD all Eligible Energy in that hour in excess of the Hourly Firm Energy Amount not exceeding an amount equal to the Hourly Firm Energy Amount for that hour.

22. The definition of "**Tier 2 Non-Firm Energy**" in Appendix 3 is deleted and replaced with the following:

"**Tier 2 Non-Firm Energy**" means in each hour during the Term after COD all Non-Firm Energy in excess of the Tier 1 Non-Firm Energy for that hour.

23. Section 3.5 of Appendix 3 is deleted.

PART B - PROJECTS THAT RECEIVE GREEN CREDIT

This Part applies to Sellers that tendered the Green Attributes to BC Hydro in the CFT process.

1. **Definitions -** The following definitions are added to Appendix 1:

"**Green Reduction Amount**" or "**GRA**" means $3.00/ MWh as adjusted effective as of January 1 in each year after the Effective Date in accordance with the following formula:

$GRA_n = \$3.00/MWh * CPI_{January\ 1\ n}/CPI_{January\ 1\ 2006}$

Where:

n= the year for which the Green Reduction Amount is being calculated

$CPI_{January\ 1\ n}$ = the CPI for December in the year immediately prior to the year for which the Green Reduction Amount is being calculated.

"**EcoLogo^M Certified Energy Amount**" means the amount of Eligible Energy in each year that qualified for the EcoLogo^M designation as evidenced in a certificate delivered by the Seller to the Buyer under section 7A.5.

"**On-Site Emission Reduction Rights**" means any credit, reduction right, offset, allowance, allocated pollution right, certificate or other unit of any kind whatsoever, whether or not tradeable, resulting from, or otherwise related to the reduction, removal, avoidance, sequestration or mitigation of emissions at or from the Seller's Plant.

2. The definition of "**Green Attributes**" in Appendix 1 is amended by deleting subsection (b)(ii) from that definition and by adding the following words at the end of the definition: "but excluding any On-Site Emission Reduction Rights and any of the foregoing that arise in connection with Pre-COD Energy, other than Test Energy paid for by the Buyer under section 2.2 of Appendix 3".

3. Subsection 6.2(a) is amended by adding the words "and under section 7A.5" after the words "subsection 6.3(f)".

4. **Replacement of section 7.10** - Section 7.10 is deleted and the following is added as Article 7A:

7A. - GREEN ATTRIBUTES

7A.1 **Transfer of Green Attributes** - The Seller hereby transfers, assigns and sets over to the Buyer all right, title and interest in and to the Green Attributes. The Buyer shall not be required to make any payment for the Green Attributes other than payment for Eligible Energy in accordance with Appendix 3. The Seller, upon the reasonable request of the Buyer, shall do, sign or cause to be done or signed all further acts, deeds, things, documents and assurances required to give effect to this section.

7A.2 **On-Site Emission Reduction Rights** - The Seller retains all right, title and interest in and to any On-Site Emission Reduction Rights.

7A.3 **Exclusivity** - Except as set out in section 7A.13, the Seller shall not commit, sell, or transfer any Green Attributes to any Person other than the Buyer, or otherwise use or apply any Green Attributes for any purpose whatsoever at any time during the Term. The

Seller shall ensure that all marketing materials produced by or for the Seller, all public or other statements by the Seller and all other communications by the Seller in any form whatsoever, contain no false or misleading statements concerning the ownership of the Energy or Green Attributes or the destination, end user or recipient of the Energy or Green Attributes. The Seller acknowledges that damages are not an adequate remedy to the Buyer for a breach by the Seller of this section and that the Buyer shall be entitled to an injunction to prevent any breach by the Seller of this section and to an order requiring the Seller to take such other actions as may be required to remedy the effects of any breach of this section.

7A.4 **Representations and Warranties** - The Seller represents and warrants to the Buyer and acknowledges that the Buyer is relying on those representations and warranties in entering into this EPA that the Seller is the legal and beneficial owner of the Green Attributes free and clear of all liens, claims, charges and encumbrances of any kind whatsoever and no other Person has any agreement or right of any kind whatsoever to purchase or otherwise to acquire or to claim or otherwise make any use whatsoever of the Green Attributes.

7A.5 **EcoLogo^{M} Certification** - The Seller shall obtain EcoLogo^{M} Certification by the first anniversary of COD and shall maintain the EcoLogo^{M} Certification throughout the remainder of the Term. By May 15 in each year after COD, the Seller shall deliver to the Buyer a certificate issued pursuant to Environment Canada's Environmental Choice^{M} program certifying the amount (MWh) of Eligible Energy delivered by the Seller to the Buyer in the immediately preceding year that qualified for the EcoLogo^{M} designation. The Seller shall notify the Buyer forthwith if the seller fails to obtain EcoLogo^{M} Certification by the date specified in this section or if at any time during the Term the Seller does not have EcoLogo Certification.

7A.6 **Alternate Certification** - The Seller shall at the Buyer's request and at the Buyer's cost use commercially reasonable efforts to apply for and diligently pursue and maintain any additional or alternate certification, licensing or approval offered by any Governmental Authority or independent certification agency evidencing that the Seller's Plant and the Energy has Green Attributes. Any failure by the Seller to use commercially reasonable efforts pursuant to this section is a "material default" for purposes of this EPA, and the Buyer may terminate the EPA under subsection 15.1(d).

7A.7 **Fees** - Except as set out in this section, the Buyer shall reimburse the Seller for all certification, audit and licensing fees paid by the Seller to obtain the EcoLogo^{M} Certification (including the annual certificate described in section 7A.5) or any alternate certification under section 7A.6, but excluding any fees to obtain the letter from TerraChoice Environmental Marketing required pursuant to the CFT. The Buyer shall reimburse the Seller for such fees within 30 days after receipt of an invoice, together with reasonable supporting information, for such fees. The Buyer shall not be required to pay for any audit or other certification process in which the Seller's Plant and all or part of the Energy does not qualify for EcoLogo^{M} Certification, or for any audit or recertification process following a loss of EcoLogo^{M} Certification by the Seller's Plant, and the Seller shall pay all costs associated with any such audit and certification process.

7A.8 **Energy Price Reduction** - If:

(a) the Seller fails to obtain EcoLogo^{M} Certification by the date specified in section 7A.5; or

(b) at any time during the Term the Seller's Plant does not have EcoLogo^{M} Certification for any reason whatsoever,

then the Escalated Bid Price for Eligible Energy will be reduced by an amount equal to the Green Reduction Amount. In the case of subsection (a) above, such reductions shall take effect from COD and the Seller shall within 30 days after receipt of an invoice from the Buyer, refund to the Buyer an amount equal to the Green Reduction Amount multiplied by the amount of Eligible Energy in respect of which the Seller has received payment from and after COD. In the case of subsection (b) above the reduction will take effect from and after the date on which the EcoLogo^{M} Certification ceased to be in effect and the Seller shall within 30 days after receipt of an invoice from the Buyer, refund to the Buyer an amount equal to the Green Reduction Amount multiplied by the amount of Eligible Energy in respect of which the Seller has received payment from and after the date on which the EcoLogo^{M} Certification ceased to be in effect. For greater certainty, notwithstanding any payment reduction pursuant to this section, the Buyer will throughout the remainder of the Term have title to the Green Attributes and the provisions of section 7A.3 will remain in effect.

7A.9 **Restoration of Price** - If the Escalated Bid Price is reduced under section 7A.8 and thereafter the Seller demonstrates to the Buyer that the Seller's Plant has obtained EcoLogo^{M} Certification, other than as a result of expenditures by the Buyer under section 7A.10, or if the Seller obtains an alternate certification at the Buyer's request under section 7A.6, then from and after the date on which the Seller provides such evidence to the Buyer or obtains such alternate certification the Escalated Bid Price will no longer be reduced by an amount equal to the Green Reduction Amount.

7A.10 **Cure by the Buyer** - If the Seller fails to obtain or maintain EcoLogo^{M} Certification, as required under section 7A.5 or any alternate certification under section 7A.6, then in addition to applying the payment reduction specified in section 7A.8 (applicable only to the EcoLogo^{M} Certification), the Buyer in its sole and unfettered discretion, may direct the Seller to take all steps required to obtain EcoLogo^{M} Certification or an alternate certification by implementing measures that are technologically feasible and not inconsistent with Good Utility Practice, Permits or Applicable Laws and the Seller shall comply promptly and diligently with that direction. Except where the failure to obtain or maintain EcoLogo^{M} Certification or an alternate certification results from a breach of Laws or Permits, the Buyer shall reimburse the Seller for reasonable direct capital and incremental operating costs incurred by the Seller resulting from compliance with the Buyer's direction within 30 days after submission of an invoice and supporting documentation reasonably satisfactory to the Buyer to evidence such costs. The Seller shall maintain accurate and complete records of such costs, and the Buyer or its designated representative may audit such costs and in that event the Seller shall provide all reasonable cooperation to the Buyer or its designated representative including access to all original records related to such costs. For greater certainty, notwithstanding the performance and completion of compliance measures under this section and the grant or reinstatement of EcoLogo^{M} Certification, the payment reductions under section 7A.8 will

continue in effect for the remainder of the Term and the Buyer will continue to have title to the Green Attributes.

7A.11 **Termination** - If the Seller fails to comply promptly and diligently with a direction under section 7A.10 and such failure is not cured within 30 days of notice from the Buyer to the Seller, then the Seller will be in material default of its obligations under this EPA and the Buyer may terminate the EPA under subsection 15.1(d).

7A.12 **Exclusive Remedy** - The remedies set out or referenced in sections 7A.6, 7A.8, 7A.10 and 7A.11 are the sole and exclusive remedies available to the Buyer for any failure by the Seller to obtain or maintain EcoLogo^{M} Certification or any alternate certification.

7A.13 **Transfer to Governmental Authority** - If the Seller has been notified that the Seller's Plant or the Energy qualifies for Canada's Renewable Power Production Incentive or Wind Power Production Incentive or any other Governmental Authority incentive associated with the generation of energy with specified environmental attributes and the transfer of the Green Attributes to the applicable Governmental Authority is required for the Seller to obtain the incentive, the Buyer shall transfer the Green Attributes to such Governmental Authority, provided that the Seller has given notice to the Buyer pursuant to this section by not later than COD. If the Buyer is required to transfer the Green Attributes to a Governmental Authority pursuant to this section, then the Parties shall enter into an amendment to this EPA to delete Article 7A from the EPA and to reduce the Escalated Bid Price by an amount equal to the Green Reduction Amount for all Eligible Energy delivered or deemed to be delivered from and after the date of the notice by the Seller to the Buyer under this section and the Seller shall within 15 days after receipt of an invoice, reimburse the Buyer for all costs incurred by the Buyer under section 7A.7 prior to the date of notice from the Seller under this section.

7A.14 **Information Requirements** - Without limiting section 6.5, the Seller shall maintain, and shall within 10 Business Days after a request from the Buyer, provide to the Buyer: (a) all information the Buyer requires to verify the quantity of Energy generated by the Seller's Plant, qualification of the Seller's Plant and all or part of the Energy for EcoLogo^{M} Certification or an alternate certification under section 7A.6, the status of the EcoLogo^{M} Certification or an alternate certification under section 7A.6, and the existence, nature and quantity of Green Attributes; (b) any information required for the purposes of any Green Attribute or energy tracking system as directed by the Buyer; and (c) any other information the Buyer requires to enable the Buyer or its Affiliates to obtain or realize the full benefit of the Green Attributes, including sales of the Green Attributes to third parties, provided that if the Buyer requests any information pursuant to subsection (b) or (c) above that the Seller would not otherwise be required to maintain for purposes of administering this EPA, the Buyer shall reimburse the Seller for all reasonable costs incurred by the Seller in obtaining or maintaining such information.

7A.15 **Audit Rights** - The Buyer, any Affiliate of the Buyer and any third Person who has entered into a contract with the Buyer or any Affiliate of the Buyer to purchase Green Attributes may at any time during the Term conduct or have a third Person with the necessary expertise conduct, at the Buyer's expense, an audit of the Project Assets to verify compliance with the requirements for EcoLogo^{M} Certification or an alternate certification under section 7A.6. The Seller shall promptly provide any consents required to enable the Buyer, any Affiliate of the Buyer or any third Person who has entered into a contract with the Buyer to purchase Green Attributes to: (i) make enquiries with

Governmental Authorities concerning the status of compliance by the Seller and the Seller's Plant with applicable Laws and Permits; (ii) make enquirities of TerraChoice Environmental Marketing or any other third Person regarding the status of the EcoLogo^{M} Certification; and (iii) obtain copies of all audits, reviews or inspections conducted by the Seller, TerraChoice Environmental Marketing or any other third Person in connection with the application by the Seller to obtain and maintain EcoLogo^{M} Certification, or any alternate certification under section 7A.6.

7A.16 **Confidentiality** - The Seller consents to the disclosure to any Person or any Governmental Authority of any Confidential Information with respect to the Energy and/or the Seller's Plant the Buyer is required to disclose to enable the Buyer to obtain or realize the full benefit to the Buyer of the Green Attributes, including sales of Green Attributes to third parties.

7A.17 **Annual Payment Calculation** - By not later than June 15 in each year after COD the Seller shall pay to the Buyer an amount calculated in accordance with the following formula:

Payment Amount = the greater of (**a**) zero and (**b**) the amount determined in accordance with the following formula:

[(AxB)-C] x GRA

Where:

A = the percentage of Energy Source(s), as set out in Appendix 5, that is designated as acceptable to generate energy that qualifies for EcoLogo^{M} Certification in the letter from TerraChocie Environmental filed with the Seller's Tender.

B = the total amount of Eligible Energy (as determined under subsection (a) of the definition of Eligible Energy) delivered by the Seller to the Buyer in the immediately preceding year.

C = the EcoLogo^{M} Certified Energy Amount.

The foregoing amount shall only be payable by the Seller for periods in which subsection 7A.8 does not apply.

5. Subsection 15.3(b)(ii)(A) is amended by adding the following as subsection (V): "Article 7A with respect only to Green Attributes associated with Eligible Energy delivered prior to termination of the EPA; and".

PART C - PROJECTS THAT TRANSFER GHG EMISSION OFFSET LIABILITY TO BUYER

This Part applies to Sellers that elected in the CFT process to transfer to BC Hydro responsibility for any regulatory obligation to purchase GHG-related Compliance Units up to the Guaranteed GHG Intensity tendered by the Seller in the CFT process.

1. Definitions - The following definitions are added to Appendix 1:

"**Actual GHG Intensity**" means the actual GHG Intensity of the Seller's Plant in each year.

"**GHG Intensity**" means:

(i) the GHG intensity for the Seller's Plant determined in the manner specified under any Laws or Permits applicable to the Seller's Plant, provided that notwithstanding any provision to the contrary in any such Laws or Permits, the GHG intensity for the Seller's Plant will be determined without regard to any other facilities owned or operated by the Seller, any Affiliate of the Seller or any other Person; or

(ii) if there is no Law or Permit in effect which specifies the method of calculating the GHG intensity for the Seller's Plant, the GHG intensity determined by dividing the total GHG emissions from the Seller's Plant in the year for which the calculation is being conducted (expressed as metric tonnes of CO_2 equivalent) by the total amount of Eligible Energy (as determined under subsection 7(a) of the definition of "Eligible Energy") for that year.

"Guaranteed GHG Intensity" means ___TO#6_____ metric tonnes CO_2 e/ MWh.

2. Section 6.8 is amended by adding the following words at the beginning of that section:

"Subject to section 6.12:"

3. The following is added as section 6.12:

6.12 GHG Compliance Unit Obligation - In each year after COD, on or before the date required pursuant to applicable Laws and Permits, and provided that the Seller has complied with its obligations under this section, the Buyer shall deliver to the Seller that number of Compliance Units calculated in accordance with the following formula:

RCUs = the greater of: (i) zero and (ii) ([the lesser of AGHGI and GGHGI] - PI) * DE

Where:

RCUs = the number of Compliance Units (in metric tonnes CO_2 e/MWh) the Buyer is required to deliver to the Seller

AGHGI = the Actual GHG Intensity

GGHGI = the Guaranteed GHG Intensity

PI = the GHG Intensity permitted under applicable Laws and Permits for the Seller's Plant

DE = the amount of Eligible Energy delivered by the Seller to the POI during the immediately preceding calendar year.

The Seller shall: (a) by the date that is 30 days prior to the date on which the Buyer is required to deliver Compliance Units to the Seller under this section, deliver a statement to the Buyer, together with all information required to support the statement, setting out the GHG intensity target for the Seller's Plant under applicable Laws and Permits, the Actual GHG Intensity for the immediately preceding year, and the number of Compliance Units the Buyer and the Seller are required to obtain by the date specified in this section; and (b) if the Actual GHG Intensity exceeds the Guaranteed GHG Intensity, obtain any Compliance Units required under applicable Laws and Permits with respect to such excess intensity and provide evidence to the Buyer that the Seller has obtained such Compliance Units. The Seller is responsible for obtaining any Compliance Units required for the period prior to COD. The parties shall enter into any amendment to this section required to reflect the reporting and compliance dates established under applicable Laws and Permits regulating GHG emissions from the Seller's Plant.

PART D - GHG COMPLIANCE COMMITMENT

This Part applies to Sellers that elect in the CFT process to comply with a contractually binding GHG intensity.

1. The following is added as section 6.12 as applicable:

   6.12 GHG Compliance Commitment - The Seller shall ensure that the Seller's Plant has a GHG intensity of not more than _TO#7__ metric tonnes CO_2e/MWh in each year. The Seller shall in the reports required to be delivered by the Seller pursuant to subsection 6.8(a) detail the status of compliance by the Seller with this section during the immediately preceding calendar quarter. If the Seller is not in compliance with the requirements of this section and the Seller fails to remedy such non-compliance within 30 days after the date of notice from the Buyer to the Seller, the Buyer may, but is not required to, on behalf of the Seller, purchase those Compliance Units that are required to remedy, in whole or in part, the Seller's non-compliance with the requirements of this section and the provisions of section 6.8(a) shall apply to such purchase, *mutatis mutandis*. Any failure by the Seller to comply with this section is a "material default" for the purposes of the definition of "Buyer Termination Event" in Appendix 1. Notwithstanding the foregoing, the Seller remains bound by the provisions of section 6.8 in addition to the foregoing commitment.

2. Subsection 9.5(a) is amended by adding the words "or section 6.12" at the end of that subsection.

3. Subsection 9.5(b) is amended by adding the words "or section 6.12" after the words "section 6.8" wherever those words appear in that subsection.

4. Section 12.5 is amended by adding the words "or 6.12" after the words "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

5. Section 13.3 is amended by adding the words "or 6.12" after the word "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

6. Subsection 15.3(a) is amended by adding the words "or 6.12" after the word "6.8" in that section, and by deleting the word "or" before the word "6.8" in that section.

PART E - PROJECTS INTERCONNECTED TO THE TRANSMISSION SYSTEM OR DISTRIBUTION SYSTEM THROUGH AN INDUSTRIAL HOST FACILITY

This Part applies to Sellers that tendered a Project that has an Indirect Interconnection (as defined in the CFT Glossary) to the Transmission System/Distribution System through an industrial host facility.

1. The provisions of this Part E are applicable for so long as the Electrical Host purchases electricity from the Buyer. If the Electrical Host ceases to purchase electricity from the Buyer, the provisions of this Part E, other than sections 5 and 6, cease to have effect, the Seller shall be required to deliver all Energy to the POI or to such other point of interconnection with the ***[Distribution System/Transmission System]*** as the Parties may agree in writing and the Parties shall enter into an amendment to the EPA to reflect the foregoing. ***[Note to Bidders: The words in bold will be finalized depending on the POI for the bidder's plant.]***

2. Section 6.4 is amended by adding the words "or on the Electrical Host" after the words "materially adverse effect on the operation of the Seller's Plant".

3. Section 7.6 is amended by adding the following at the end of that section:

   Deliveries of Eligible Energy to an Electrical Host to service the Electrical Host's electricity requirements will be deemed to be deliveries of Eligible Energy to the Buyer at the POI for purposes of this EPA to the extent such deliveries displace deliveries of electricity from the Buyer to the Electrical Host.

4. Appendix 1 is amended by:

   (a) adding the following definition:

   "**Electrical Host**" means a facility which is not itself an electrical generating facility and which is located between the Seller's Plant and the POI, where the Seller's Plant is providing electricity to the facility and the Seller's Plant does not have an independent connection to the *[Transmission System/Distribution System]*.

   [Note to Bidders - Where a Bidder is proposing to Tender a Project that is interconnected to the Distribution System or the Transmission System through an Electrical Host, BC Hydro will review its electricity supply contract(s) relating to that Electrical Host and will advise the Bidder prior to the Tender Closing Time of any amendments required to such electricity supply contract(s) to accommodate the Project. Any Tender for such a Project will be deemed to incorporate those amendments or must be accompanied by an appropriate amending agreement signed by the owner of the Electrical Host.]

   (b) deleting the definition of "**POI**" and replacing it with the following:

   "**POI**" or "**Point of Interconnection**" means the point of interconnection which is the point at which the Electrical Host interconnects with the ***[Transmission System/Distribution System]*** as more particularly described in the interconnection agreement between the Electrical Host and the ***Transmission Authority/Distribution Authority***."

5. Everywhere in this EPA where the words "Energy delivered to the POI" or words of similar meaning appear, the words "or deemed pursuant to section 7.6 to be delivered to the POI" are deemed to follow immediately thereafter.

6. All of the provisions of Part G, Appendix 10 are applicable.

7. The Seller will be responsible for, and shall pay within 30 days after receipt of an invoice from the Buyer, all costs reasonably incurred by the Buyer and/or the Electrical Host as required to implement any amendments required to any Electricity Supply Agreement between the Buyer and the Electrical Host as a result of provisions of section 7.5 of the EPA and the interconnection arrangements for the Seller's Plant.

PART F - PROJECTS INTERCONNECTED TO THE DISTRIBUTION SYSTEM

This Part applies to Sellers that tendered a Project that interconnects with the Distribution System.

1. Subsection 4.2(a) is amended by adding the words "Distribution Authority and the" before the words "Transmission Authority" in that subsection.

2. Section 4.5 is amended by:

   (a) deleting the words "Transmission System" and replacing them with "Distribution System"; and

   (b) adding the words "and the Distribution Authority" after the words "Transmission Authority" in that section.

3. Subsection 5.2(d)(i) is amended by deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

4. Section 5.6 is amended by:

   (a) adding the words "and Direct Assignment Facilities" after the words "Network Upgrades" wherever the words "Network Upgrades" appear in that section; and

   (b) adding the words "or the Distribution Authority" after the words "the Buyer" in the first sentence of that section.

5. Section 5.7 is amended by adding the words "Distribution Authority and" before the words "Transmission Authority" wherever those words appear in that section.

6. Wherever the words "Facilities Agreement" appear in the EPA, except in the heading to section 20.9, the heading to subsection 6.6(d) and in the definition of "Facilities Agreement" in Appendix 1, the words ", if any," are added immediately thereafter.

7. Section 6.3 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

8. Section 6.4 is amended by adding the words "and the Distribution Authority's" after the words "Transmission Authority's".

9. Section 6.9 is amended by adding the words "and the Distribution Authority" after the words "the Transmission Authority" in that section.

10. Subsection 7.8(a) is amended by deleting the words "Transmission System" and replacing them with "Distribution System" and deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

11. Subsections 7.8(b)(ii) and (iii) are deleted and replaced with the following and subsection (iv) is renumbered as subsection (iii):

   (ii) disconnection of the Seller's Plant from the Distribution System, and any Outage, suspension, constraint or curtailment in the operation of the Distribution System preventing or limiting physical deliveries of Eligible Energy at the POI, provided that the

disconnection, Outage, suspension, constraint or curtailment: (A) results from any Outage, suspension, constraint, curtailment or other event of any kind on the Distribution System; or (B) is implemented pursuant to the Interconnection Agreement, Facilities Agreement, if any, or any other legally enforceable right;

12. Subsection 7.9(a) is deleted and replaced with the following:

"(a) any disconnection of the Seller's Plant from the Distribution System or any Outage or Outages on the Distribution System or any suspension, constraint or curtailment in the operation of the Distribution System preventing or limiting physical deliveries of Eligible Energy at the POI where such Outages, suspensions, constraints or curtailments exceed, in the aggregate 24 hours, whether or not continuous, in that month, other than a disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant; or"

13. Section 8.1 is amended by adding the words "and Distribution Authority" after the words "Transmission Authority".

14. Subsection 11.2(f) is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

15. Section 20.9 is deleted and replaced with the following:

"**20.9 Interconnection Agreement and Facilities Agreement -** Nothing in the Interconnection Agreement or the Facilities Agreement, if any, and no exercise of any right thereunder, restricts or otherwise affects any right, obligation or liability of either Party under this EPA, except to the extent set out expressly herein, and no notice, consent, approval or other communication or decision under or in relation to the Interconnection Agreement or the Facilities Agreement, if any, shall constitute or be relied upon as a notice, consent, approval or communication or decision under this EPA, and this EPA shall be interpreted and applied as though the Distribution Authority were a third party, including for purposes of determining whether or not a Force Majeure has occurred."

16. The definition of "**Buyer Termination Event**" in Appendix 1 is amended by deleting subsection (c) from that definition and replacing it with the following:

"(c) the Seller has not by the date that is the earlier of: (i) 60 days after the date of award of this EPA pursuant to the CFT; and (ii) 240 days after the date of issuance by the Distribution Authority to the Seller of the F2006 CFT Preliminary Interconnection Study Report, executed and delivered to the Distribution Authority an application for an impact/design study where the interconnection of the Seller's Plant will have no impact on the Transmission System, or, where the interconnection of the Seller's Plant will have an impact on the Transmission System, an interconnection impact study and any related studies, together with the applicable study fee in the form and amount prescribed by the Distribution Authority;"

17. The definition of "**Combined Study Agreement**" in Appendix 1 is deleted.

18. The definition of "**Facilities Agreement**" in Appendix 1 is amended by deleting the words "Transmission Authority" and replacing them with "Distribution Authority".

19. The definition of "**Force Majeure**" in Appendix 1 is amended by adding the words "or the Distribution Authority" after the words "Transmission Authority" in that section.

20. The words "Transmission System" in the definition of "**Interconnection**" in Appendix 1 are deleted and replaced with the words "Distribution System".

21. The words "Transmission Authority" in the definition of "**Interconnection Agreement**" in Appendix 1 are deleted and replaced with "Distribution Authority".

22. The definition of "**Outage**" in Appendix 1 is amended by adding the words "Distribution System and" before the words "Transmission System" in that definition.

23. The definition of "**POI**" in Appendix 1 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

24. The definition of "**Seller's Plant**" in Appendix 1 is amended by deleting the words "Transmission System" and replacing them with "Distribution System".

25. If Part G of Appendix 10 is applicable, then:

    (a) paragraph 11 of this Part is amended by deleting the words "and subsection (iv) is renumbered as subsection (iii)" and replacing them with the words "and subsections (iv) and (v) are renumbered as subsections (iii) and (iv);

    (b) subsection 7.8(b)(iv), as added by Part G of Appendix 10 and renumbered by section 11 of this Part F, is amended by deleting the words "Transmission System" and replacing them with "Distribution System";

    (c) subsection 7.9(a) is deleted and replaced with the following:

    "any disconnection of the Seller's Plant or the Private Line from the Distribution System or any Outage or Outages on the Distribution System or any suspension, constraint or curtailment in the operation of the Distribution System, exceeding in the aggregate 24 hours, whether or not continuous, in that month, other than a disconnection, Outage, suspension, constraint or curtailment attributable to the Seller or the Seller's Plant or to the Private Line Owner or any of the Private Line Owner's facilities; or";

    (d) subsection 11.2(i), as added by Part G of Appendix 10, is amended by deleting the words "Transmission System" and replacing them with "Distribution System";

    (e) subsection (c) of the definition of "**Buyer Termination Event**" as amended by paragraph 16 of this Part F is amended by adding the words "or the Private Line Owner" after the word "Seller" wherever that word appears in that subsection;

    (f) the Note to Bidders under the definition of "**POI**" as added by Part G of Appendix 10 is amended by deleting the word "Transmission" and replacing it with "Distribution"; and

(g) the definition of "**Private Line**" and the related Note to Bidders as added by Part G of Appendix 10, is amended by deleting the word "Transmission" and replacing it with "Distribution".

26. If Part I of Appendix 10 (Split Bid Projects) applies, then section 4.6 of the EPA (added by Part I of Appendix 10) is amended by adding the words "or the Distribution Authority" after the words "Transmission Authority" in that section.

PART G - PROJECTS INTERCONNECTED TO THE TRANSMISSION SYSTEM OR DISTRIBUTION SYSTEM THROUGH A PRIVATELY-OWNED TRANSMISSION OR DISTRIBUTION LINE

This part applies to Sellers who submit an F2006 CFT Preliminary Interconnection Study Report with their Tenders which indicates that the Seller's Plant will be interconnected to the Transmission System or Distribution System through a privately-owned transmission or distribution line, including a Project that has an Indirect Connection through an industrial host facility.

1. Section 4.2 is amended by:

   (a) adding the following as subsection (e) and renumbering existing subsections (e) and (f) as (f) and (g):

   "(e) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Plant Capacity and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required";

   (b) deleting the words "subsections (a) and (c)" in the sentence immediately following subsection (g) (as renumbered in accordance with the foregoing) and replacing them with "subsections (a), (c) and (e)".

2. Section 4.5 is amended by:

   (a) deleting the first sentence and replacing it with the following:

   "If the Private Line Owner makes any change to the point of interconnection between the Private Line and the Transmission System (including any change to the point of interconnection specified in the F2006 CFT Preliminary Interconnection Study Report), the Seller shall notify the Buyer forthwith upon the Seller becoming aware of such change or proposed change and the Seller shall enter into an amendment to this EPA as required to put the Buyer in the position it would have been in under this EPA had the point of interconnection between the Private Line and the Transmission System not been changed, including with respect to the amount of Eligible Energy."; and

   (b) adding the words "or the Private Line Owner" after the word "Seller" at the beginning of the second sentence.

3. Subsection 5.2(c) is amended by adding the words "or under the Private Line Agreement" at the end of that subsection.

4. Subsection 5.2(d)(i) is amended by adding the words "or the Private Line Owner" after the words "to the Seller".

5. Section 5.2 is amended by:

   (a) adding the following as subsection 5.2(e) and changing the comma at the end of subsection 5.2(d) to a semicolon, adding the word "and" after the semicolon and deleting the word "and" at the end of subsection 5.2(c):

   "(e) the Private Line Owner is not in default under the Interconnection Agreement or the Facilities Agreement,"; and

   (b) deleting the words "subparagraphs (a) to (d)" in the last sentence of that Section and replacing them with "subparagraphs (a) to (e)".

6. Subsection 6.3(g) is amending by adding the words and the Private Line Agreement" at the end of that subsection.

7. Subsection 6.6(d) is amended by adding the words "or the Private Line Agreement" after the words "Interconnection Agreement" and by adding the words "or the Private Line Owner" after the word "Seller" at the end of the subsection.

8. Section 6.9 is amended by adding the following at the end of that section:

   "The Seller shall promptly on request by the Buyer provide to the Buyer a consent in similar form signed by the Private Line Owner for delivery to the Transmission Authority provided that in such consent all references to the "Seller" in subsections (a) and (d) will be replaced by the "Private Line Owner".

9. Section 6.10 is amended by:

   (a) adding the following after the first sentence in that section:

   "The Seller shall use commercially reasonable efforts to obtain any information or cooperation that may be required from the Private Line Owner to complete those studies and cost estimates."; and

   (b) adding the words "(including reasonable amounts paid to the Private Line Owner to reimburse the Private Line Owner for costs incurred in providing information or cooperation as requested by the Buyer)" after the words "all reasonable costs incurred by the Seller".

10. Section 7.2 is amended by adding the following as subsection (e) and changing the period at the end of subsection (d) to a semicolon and inserting the word "and" and deleting the word "and" at the end of subsection 7.2(c):

    "(e) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Monthly Firm Energy Amounts and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required."

11. Subsection 7.8(a) is amended by:

    (a) adding the words "or the Private Line Owner or any of the Private Line Owner's facilities" at the end of subsections 7.8(a)(ii) and (iii); and

    (b) adding the following as subsection (vi) and by changing the period at the end of subsection (v) to a semicolon and adding the word "and" after the semicolon and deleting the word "and" at the end of subsection (iv):

        "(vi) disconnection of the Private Line from the Transmission System by the Transmission Authority for reasons that are not attributable to the Seller or the Seller's Plant or the Private Line Owner or any of the Private Line Owner's facilities.".

12. Subsection 7.8(b) is amended by adding the following as subsection (v) and by changing the period at the end of subsection (iv) to a semicolon and adding the word "and" after the semicolon and deleting the word "and" at the end of subsection (iii):

    "(v) disconnection of the Private Line from the Transmission System for reasons not attributable to the Buyer.".

13. Subsection 7.9(a) is amended by:

    (a) adding the words "or the Private Line" after the words "Seller's Plant" in the first line;

    (b) adding the words "or the Private Line" after the words "Seller's Plant" in subsection 7.9(a)(i); and

    (c) adding the words "or to the Private Line Owner or any of the Private Line Owner's facilities" at the end of the subsection.

14. Subsection 8.1(c) is amended by adding the following at the end of that subsection:

    "and after adjusting for any incremental losses associated with the transmission of energy from any other generating facility connected to the Private Line where: (i) the output from that other generating facility is sold to the Buyer; (ii) the incremental losses have not been accounted for in the calibration of the meter for the other generating facility; and (iii) "incremental losses" refers to those losses that would not have occurred but for the transmission of Energy from the Seller's Plant to the POI through the Private Line".

15. Subsection 11.2(e) is amended by adding the words "including any act or omission of the Private Line Owner" after the words "of a Party".

16. Section 11.2 is amended by adding the following as subsection (h) and by deleting the period at the end of subsection (g) and replacing it with a semicolon and by adding the word "or" after the semicolon and deleting the word "or" at the end of subsection (f):

    "(h) for any disconnection of the Private Line from the Transmission System or any Outage, constraint or curtailment in the operation of the Private Line, except to the extent such disconnection, Outage, constraint or curtailment in operation would be excused by reason of Force Majeure as defined in this EPA.".

17. Subsection 18.1(c) is amended by adding the words "or the Private Line" after the words "Seller's Plant".

18. Appendix 1 is amended by:

(a) adding the following definitions:

"**Private Line**" means the line owned by _____ as at the Effective Date extending from _____ to the Transmission System as indicated on Schedule 1 to Appendix 5. ***[Note to Bidders: The blanks in this section will be completed based on the information contained in the Bidder's Tender as supplemented, as required, by information provided by the Transmission Authority.]***

"**Private Line Agreement**" means the agreement between the Seller and the Private Line Owner pursuant to which the Seller is authorized to transmit Energy from the Seller's Plant along the Private Line to the POI.

"**Private Line Owner**" means the owner of the Private Line from time to time.

(b) amending subsection (c) of the definition of "**Buyer Termination Event**" by adding the words "or the Private Line Owner" after the word "Seller" wherever that word appears in that subsection;

(c) amending the definition of "**Combined Study Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(d) amending the definition of "**Facilities Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(e) amending subsection (f) in the definition of "**Force Majeure**" by deleting everything from the words "and such delay" to the end of the subsection and replacing them with the following:

"and such delay is not attributable to the Seller or the Seller's Plant or to the Private Line Owner or any of the Private Line Owner's facilities, including any change to the point of interconnection with the Transmission System or other Project change made by the Seller or the Private Line Owner as described in section 4.5";

(f) amending the definition of "**Interconnection**" by adding the words "along the Private Line" after the words "Seller's Plant";

(g) amending the definition of "**Interconnection Agreement**" by adding the words "or the Private Line Owner" after the word "Seller";

(h) deleting the definition of "**POI**" and replacing it with the following:

"**POI**" or "**Point of Interconnection**" means _____. ***[Note to Bidders – This will be the point of interconnection between the Private Line and the Transmission System. This blank will be completed based on the information in the Bidder's Tender as supplemented, as required, by information provided by the Transmission Authority.]***

(i) amending the definition of "**Project Assets**" by adding the words "and all agreements with the Private Line Owner" at the end of the definition; and

(j) amending the definition of "**Seller's Plant**" by adding the words "but excluding the Private Line" at the end of the definition.

19. Section 3 of Appendix 4 is amended by:

(a) adding the words "or the Private Line Agreement" at the end of the second sentence of that section; and

(b) adding the following sentence at the end of section 3:

"The Private Line Owner is not in material default under the Interconnection Agreement or the Facilities Agreement".;

20. If Part A of Appendix 10 is applicable, Section 7.2 as amended by Part A is amended by adding the following as subsection (d) and by changing the period at the end of subsection (c) to a semicolon and adding the word "and" at the end of subsection (c):

"(d) the Seller has entered into an agreement with the Private Line Owner amending the Private Line Agreement as required to accommodate the increase or decrease in the Hourly Firm Energy Amount and has provided a copy of the amending agreement to the Buyer (with any confidential information redacted) or has provided evidence satisfactory to the Buyer, acting reasonably, that no such amendments are required."

21. If Part E of Appendix 10 is applicable, the definition of "POI" in Part E of Appendix 10 will be applicable instead of the definition of "POI" set out in this Part G of Appendix 10.

PART H – INTENTIONALLY DELETED

PART I - SPLIT BIDS

This Part applies to Bidders that tender only a portion of the output from the Seller's Plant to BC Hydro.

A. MONTHLY FIRM PROJECTS

1. Section 3.3 is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2."

2. The text of section 4.2 is deleted and replaced with the words "Intentionally Deleted" and all references to section 4.2 in any other section of the EPA are deleted.

3. Section 4.5 is amended by adding the words "(including any increase in the Project size)" after the words "Transmission Authority" in the second sentence of that section.

4. The following section is added as section 4.6:

   "**4.6 Network Upgrade Cost Allocation -** Regardless of how the Transmission Authority allocates Network Upgrade Costs as between the Buyer and the Seller, the Seller and the Buyer agree that the Buyer shall be responsible for that amount of the Network Upgrade Costs that is determined by multiplying the Network Upgrade Costs by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity. The Seller shall be responsible for, and shall promptly reimburse the Buyer for, any Network Upgrade Costs in excess of the Network Upgrade Costs for which the Buyer is responsible pursuant to this section."

5. Subsection 5.2(b) is amended by deleting the words "Plant Capacity multiplied by 1 hour" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2 multiplied by 1 hour".

6. Section 6.4 is amended by adding the following at the end of that section: "Notwithstanding anything in this section, the Buyer will not be required to reimburse or otherwise compensate the Seller for any impact on sales of Energy to third parties resulting from a requirement to reschedule a Planned Outage in accordance with this section."

7. Section 7.2 is amended by:

   (a) deleting the words "Plant Capacity multiplied by the number of hours in the applicable month" in subsection 7.2(b) and replacing them with "Split Bid Threshold Level for the applicable month" and

   (b) adding the following sentence at the end of that section:

   "If the Seller delivers a notice to increase or decrease the Monthly Firm Energy Amount pursuant to this section, the Seller may at the same time elect to increase or decrease the corresponding Split Bid Threshold Level by a percentage corresponding to the percentage increase or decrease in the Monthly Firm Energy Amount and in that event the amendment to Appendix 2 referred to above will include an amendment to the Split Bid Threshold Level set out in that Appendix."

8. Section 7.5 is deleted and replaced with the following:

"**7.5 Exclusivity** - The Seller shall not at any time during the Term commit, sell or deliver any Energy to any Person, other than the Buyer under this EPA, except for:

(a) Pre-COD Energy sold to third parties in accordance with section 7.1;

(b) during any period in which the Buyer is in breach of its obligations under section 7.4;

(c) during any period in which the Buyer is not accepting deliveries of Energy from the Seller due to Force Majeure invoked by the Buyer; and

(d) Energy, if any, in excess of the Split Bid Threshold Level.

From and after COD, the Seller shall not commit, sell or deliver any Energy to any Person at any time, unless the Metered Energy at that time exceeds the Split Bid Threshold Level and in that case, the Seller may only sell to third Persons that portion of Metered Energy that exceeds the Split Bid Threshold Level. All sales to third Persons authorized under this section shall be contracted in a manner that is consistent with the Seller's obligations and the Buyer's rights under this EPA. Any such sales will be subordinated in priority of delivery and in all other respects to the Buyer's rights to receive Energy from the Seller's Plant."

9. Section 7.9 is amended by deleting the words "Plant Capacity" in that section and replacing them with "Split Bid Threshold Level".

10. Section 12.5 is amended by adding the words "4.6" after "4.5" in that section, and by deleting the words "4.2,".

11. Section 13.3 is amended by adding the words "4.6" after "4.5" in that section, and by deleting the words "4.2,".

12. Section 15.3(a) is amended by adding "4.6," after "4.5," in that section, and by deleting the words "4.2,".

13. Section 15.4(a) is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2".

14. Subsection 15.5(d)(i) is deleted and replaced with the following:

"(i) 115% of the amount determined by multiplying the Development Costs by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity; and".

15. The definition "**Eligible Energy**" in Appendix 1 is deleted and replaced with the following:

"**Eligible Energy**" means in each month after COD:

(a) the amount of Metered Energy delivered by the Seller at the POI in that month; and

(b) Energy that is deemed to be "Eligible Energy" in that month pursuant to section 7.9,

but excluding all Metered Energy that exceeds the Split Bid Threshold Level.

16. The definition of "**Major Damage**" in Appendix 1 is deleted and replaced with the following:

"**Major Damage**" means damage where the cost to repair or rebuild the Seller's Plant with a Plant Capacity equivalent to the highest Split Bid Threshold Level exceeds the present value (using the Present Value Rate) of (a) the projected Energy deliveries from the Seller's Plant for the remainder of the Term (not exceeding the Split Bid Threshold Levels), multiplied by (b) the projected payments under this EPA for that Energy, (calculated on the basis that the Tier 2 Non-Firm Energy Price will be equal to the Tier 1 Non-Firm Energy Price), less a $/MWh amount determined by multiplying the estimated operating and maintenance costs for the Seller's Plant (including costs of the Energy Source) by an amount equal to the average of the Split Bid Threshold Levels divided by the Plant Capacity.

17. The definition of "**Plant Capacity**" in Appendix 1 is amended by deleting the words "as amended in accordance with section 4.2".

18. The definition of "**Performance Security**" in Appendix 1 is amended by deleting the words "Plant Capacity" and replacing them with "highest Split Bid Threshold Level set out in Appendix 2".

19. The definition of "**Pre-COD Energy**" in Appendix 1 is deleted and replaced with the following:

"**Pre-COD Energy**" means that amount of Metered Energy delivered by the Seller at the POI prior to COD including Test Energy, but excluding any portion of the Metered Energy that exceeds the Split Bid Threshold Level."

20. Appendix 1 is amended by adding the following definition:

"**Split Bid Threshold Level**" means the level of Energy output as set out in Appendix 2 that the Seller is required to deliver to the Buyer after COD before the Seller can sell any Energy to third parties.

21. The definition of "**Test Energy**" in Appendix 1 is deleted and replaced with the following:

"**Test Energy**" means Metered Energy delivered to the POI during any successful test pursuant to subsection 5.2(b), but excluding any portion of the Metered Energy that exceeds the Split Bid Threshold Level.

22. Section 4 in Appendix 3 is amended by:

(a) deleting the first formula in that section and replacing it with the following:

"$X_n * [(TRl_n * AVl_n) + (TRi_n * AVi_n)] > X_{COD} * [(TRl_{COD} * AVl_{COD}) + (TRi_{COD} * AVi_{COD})]$",

(b) deleting the second formula and replacing it with the following:

"Payment Amount = X_n multiplied by (the greater of (i) 0 and (ii) the amount determined in accordance with the following formula: $\{[(TRl_n - TRl_{COD})* AVl_n] + [(TRi_n - TRi_{COD}) *AVi_n]\} * 0.5)$"; and

(c) inserting the following under the term "Where":

"X_n = the average of the Split Bid Threshold Levels divided by the Plant Capacity in year n".

23. If Part B of Appendix 10 is applicable, the definition of "Green Attributes" is amended by deleting the word "Energy" in subsections (a) and (b) and replacing it with "Energy but not exceeding the Split Bid Threshold Level".

B. HOURLY FIRM PROJECTS

The following changes apply to Projects that tender an hourly firm split bid project in addition to the changes in Part A of Appendix 10, Part I.

24. Section 4.6, as added by Part A of this Appendix, is amended by adding the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

25. Section 7.2 is amended by:

(a) deleting the words "Plant Capacity multiplied by the number of hours in the applicable month" in subsection (b) and replacing them with "Split Bid Threshold Level for the applicable hour"; and

(b) deleting the last sentence of that section (as amended by Part A of Appendix 10, Part I) and replacing it with the following:

"If the Seller delivers a notice to increase or decrease any Hourly Firm Energy Amount pursuant to this section, the Seller may at the same time elect to increase or decrease the corresponding Split Bid Threshold Level by a percentage corresponding to the percentage increase or decrease in the Hourly Firm Energy Amount and in that event the amendment to Appendix 2 referred to above will include an amendment to the Split Bid Threshold Level set out in that Appendix."

26. Subsection 15.5(d)(i), as amended by Part A of this Appendix, is amended by inserting the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

27. Section 4 of Appendix 3, as amended by Part A of this Appendix, is amended in the definition of "X_n" by inserting the word "weighted" before the word "average", and by inserting the words "(using the Table in Part 2 of Appendix 2)" after the word "average".

PART J - SELLER IS A JOINT VENTURE OR GENERAL PARTNERSHIP

This Part applies if the Seller is a joint venture or general partnership.

1. Section 1.12 is added as follows:

   1.12 Joint and Several Liability - Each of [Partner1] and [Partner2] are jointly and severally, and not severally only, liable to the Buyer for and in respect of all liabilities and obligations of the Seller under or in relation to this EPA. All references to the "Seller" herein mean both [Partner1] and [Partner2], unless the contrary is expressly indicated. Acts or omissions of either [Partner1] or [Partner2] in relation to this EPA are deemed to be acts or omissions of the Seller.

2. Section 6.7 is deleted and replaced with the following:

   Neither the Seller nor [Partner1] or [Partner2] shall take any action that would cause the Seller, [Partner1] or [Partner2] to cease to be exempt, or omit to take any action necessary for the Seller, [Partner 1] and [Partner 2] to continue to be exempt, from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a "public utility" could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

3. Section 16.1 is deleted and replaced with the following:

   A Party, which in the case of the Seller, includes any or all of the Seller, [Partner1] and [Partner2], may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term except:

   (a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditioned; or

   (b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

   Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's, [Partner1]'s or [Partner2]'s ownership interest, in the Seller's Plant, or of all or any interest of the Seller, [Partner1] or [Partner2] in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's, [Partner1]'s or [Partner2]'s ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller, [Partner1] or [Partner2] is deemed to be an assignment of this EPA by the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller or [Partner1] or [Partner2] merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

4. Subsection 16.2(b) is deleted and replaced with the following:

   (b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller, [Partner1] or [Partner2], the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

5. Section 16.6 is deleted and replaced with the following:

   Notwithstanding subsection 16.1(a), the Seller, [Partner1] or [Partner2] shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

6. Section 18.1 is deleted and replaced with the following: The Seller and each of [Partner1] and [Partner2] as to itself only, represent and warrant to the Buyer, and acknowledge that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

   (a) Corporate Status - Each of [Partner1] and [Partner2] are duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA;

   (b) Bankruptcy - No actions have been taken or authorized by either [Partner1] or [Partner2] or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or either [Partner1] or [Partner2] or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller or either [Partner1] or [Partner2];

   (c) Assets - No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

   (d) No Conflict - Neither the signing of this EPA nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of either [Partner1] or [Partner2], any permit, franchise, lease, license, approval or agreement to which [Partner1] or [Partner2] is a party, or any other covenant or obligation binding on the Seller or either [Partner1] or [Partner2] or affecting any of their properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or

the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) Binding Obligation - This EPA constitutes a valid and binding obligation of Seller, [Partner1] and [Partner2] enforceable against Seller, [Partner1] and [Partner2] in accordance with its terms;

(f) Authorization, Execution and Delivery - This EPA has been duly authorized, executed and delivered by [Partner1] and [Partner2];

(g) Bid Documents - All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) Exemption from Regulation - The Seller, [Partner 1] and [Partner 2] are exempt from regulation as a "public utility" as defined in the UCA with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

7. Section 19.1 is amended by:

(a) adding the words "and [Partner 1] and [Partner 2]" after the word "Seller" in the first line in that section; and

(b) adding the words "or [Partner 1] or [Partner 2]" after the word "Seller" in all other places where the word "Seller" appears in that section.

8. Section 19.2 is amended by replacing the words "the Seller" with the words "the Seller [Partner 1] and [Partner 2]" in the first line thereof.

9. The definition of "**Affiliate**" in Appendix 1 is deleted and replaced with the following:

"**Affiliate**" means, with respect to the Seller, [Partner1] or [Partner2] any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller, [Partner1] or [Partner2] and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

10. The definition of "**Bankrupt or Insolvent**" in Appendix 1 is amended by adding the following after the word "Person" in the first line of that definition: "(which in the case of the Seller includes any or all of the Seller, [Partner1] or [Partner2])".

11. Subsection (a) of the definition of "Buyer Termination Event" in Appendix 1 is deleted and replaced with the following:

"(a) any one of the Seller, [Partner1] or [Partner2] is Bankrupt or Insolvent";

12. The words "the Seller is in material default" in subsection (e) of the definition of "Buyer Termination Event" in Appendix 1 are deleted and replaced with the following:

    "any one of the Seller, [Partner 1] or [Partner 2] is in material default"

13. The definition of "**COD Certificate**" in Appendix 1 is amended by adding the following after the words "officer of":

    "each of [Partner1] and [Partner2] and".

14. Note to Bidders: The description of the Parties on page 1 of the EPA and the signature block will be amended as necessary to reflect the general partnership or joint venture structure.

PART K - SELLER IS A LIMITED PARTNERSHIP

This Part applies if the Seller is a limited partnership.

1. Section 1.12 is added as follows:

   1.12 **General Partner** - All references to the "Seller" herein include [General Partner(s)], unless the contrary is expressly indicated. Acts or omissions of [General Partner(s)] in relation to this EPA are deemed to be acts or omissions of the Seller.

   [Note to Bidders: Where there is more than one General Partner the following will be added at the end of section 1.12:

   Each of [General Partner 1] and [General Partner 2] are jointly and severally, and not severally only, liable to the Buyer for and in respect of all liabilities and obligations of the Seller under or in relation to this EPA.]

2. Section 6.7 is deleted and replaced with the following:

   Neither the Seller nor [General Partner(s)] shall take any action that would cause the Seller or [General Partner(s)] to cease to be exempt, or omit to take any action necessary for the Seller and the [General Partner(s)] to continue to be exempt, from regulation as a "public utility", as defined in the UCA, with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA where such designation as a "public utility" could reasonably be expected to have an adverse effect on the Buyer or its interests under this EPA.

3. Section 16.1 is deleted and replaced with the following:

   A Party, which in the case of the Seller includes any or all of the Seller and General Partner(s), may not assign or dispose of this EPA or any direct or indirect interest in this EPA, in whole or in part, for all or part of the Term except:

   (a) with the consent of the other Party, such consent not to be unreasonably withheld, delayed or conditional; or

   (b) to an Affiliate, on notice to, but without the consent of, the other Party, provided that the assignor will remain liable for the obligations of the assignee under this EPA, unless otherwise agreed in writing by the other Party.

   Notice of intent to assign, and where applicable a request for consent to assign, must be given by the assignor to the other Party not less than 30 days before the date of assignment, and, except in the case of assignment to a Facility Lender, must be accompanied by a proposed form of assignment and assumption agreement, and, in the case of an assignment pursuant to subsection 16.1(a), other than to a Facility Lender, evidence of the capability of the assignee as required by subsection 16.2(b). Consent to an assignment to a Facility Lender will not be given or be deemed to be given until full execution and delivery of the agreement contemplated by section 16.3. Any sale or other disposition of all or a substantial part of the Seller's or [General Partner(s)]'s ownership interest in the Seller's Plant, or of all or any interest of the Seller or [General Partner(s)] in this EPA or revenue derived from this EPA, and any mortgage, pledge, charge or grant of a security interest in all or any part of the Seller's or [General Partner(s)]'s ownership interest in the Project Assets and any change of Control, merger, amalgamation or reorganization of the Seller or [General Partner(s)] is deemed to be an assignment of this EPA by

the Seller for the purpose of this Article 16, including section 16.2, provided that where Control is transferred to an Affiliate or where the Seller or [General Partner(s)] merges or amalgamates with an Affiliate or enters into a reorganization with an Affiliate, subsection 16.1(b) shall apply.

4. Subsection 16.2(b) is deleted and replaced with the following:

   (b) except for an assignment under subsection 16.1(b), the assignee demonstrating to the reasonable satisfaction of the other Party its capability (financial, technical and otherwise) to fulfil the obligations of the assignor under this EPA or, in the case of a change of Control, merger, amalgamation or reorganization of the Seller or [General Partner(s)], the parties to that transaction demonstrating to the reasonable satisfaction of the Buyer, the continued ability of the Seller to perform its obligations under this EPA and, in the case only of an assignment of 100% of the assignor's interest in the Project Assets, the Seller's Plant, or this EPA or revenue derived from this EPA, upon such demonstration and concurrently with the agreement providing for the assumption of liabilities and obligations and the provision of Performance Security required under subsection 16.2(a), the assignor shall be released from all future obligations and liabilities under the EPA and the Performance Security provided by it will be returned or released.

5. Section 16.6 is deleted and replaced with the following:

   Notwithstanding subsection 16.1(a), the Seller or [General Partner(s)] shall not assign (including any event or action that is deemed under section 16.1 to be an assignment) or otherwise dispose of any interest in this EPA prior to COD, except: (i) to an Affiliate as permitted under subsection 16.1(b); (ii) to a Facility Lender as permitted under subsection 16.1(a) and section 16.3; or (iii) with the prior consent of the Buyer, which consent may be given, withheld or conditioned in the unfettered discretion of the Buyer.

6. Section 18. 1 is deleted and replaced with the following:

   The Seller and each [General Partner(s)] as to itself only represent and warrant to the Buyer, and acknowledge that the Buyer is relying on those representations and warranties in entering into this EPA, as follows:

   (a) Corporate Status - As to the [General Partner(s)], it is duly incorporated, organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation, is registered or otherwise lawfully authorized to carry on business in British Columbia, and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and to perform its obligations under this EPA. As to the Seller, it is duly created and organized, validly existing and in good standing under the laws of the jurisdiction of its creation, is registered or otherwise lawfully authorized to carry on business in British Columbia and has full power, capacity and authority to own its assets and to carry on its business as now conducted and to enter into and perform its obligations under this EPA;

   (b) Bankruptcy - No actions have been taken or authorized by the Seller or [General Partner(s)] or any other Person to initiate proceedings for, or in respect of, the bankruptcy, insolvency, liquidation, dissolution or winding-up of the Seller or [General Partner(s)] or to appoint a receiver, liquidator, trustee or assignee in bankruptcy in respect of the Seller or [General Partner(s)];

(c) Assets - No appropriation, expropriation or seizure of all or any portion of the Seller's Plant is pending or threatened;

(d) No Conflict - Neither the signing of this EPA nor the carrying out of the Seller's obligations under this EPA will: (i) constitute or cause a breach of, default under, or violation of, the constating documents or bylaws of the Seller or [General Partner(s)], any permit, franchise, lease, license, approval or agreement to which the Seller or [General Partner(s)] is a party, or any other covenant or obligation binding on the Seller or [General Partner(s)] or affecting any of their properties; (ii) cause a lien or encumbrance to attach to the Seller's Plant, other than a security interest granted in respect of financing the design, construction or operation of the Seller's Plant; or (iii) result in the acceleration, or the right to accelerate, any obligation under, or the termination of, or the right to terminate, any permit, franchise, lease, license, approval or agreement related to the Seller's Plant;

(e) Binding Obligation - This EPA constitutes a valid and binding obligation of the Seller and [General Partner(s)] enforceable against the Seller and [General Partner(s)] in accordance with its terms;

(f) Authorization, Execution and Delivery - This EPA has been duly authorized, executed and delivered by the [General Partner(s)] on behalf of the Seller;

(g) Bid Documents - All material information in the Bid Documents is true and correct in all material respects and there is no material information omitted from the Bid Documents which makes the information in the Bid Documents misleading or inaccurate in any material respect; and

(h) Exemption From Regulation - The Seller and [General Partner(s)] are exempt from regulation as a "public utility" as defined in the UCA with respect to the Seller's Plant, the sale of Energy and the performance by the Seller of its obligations under this EPA.

7. Section 19.1 is amended by:

(a) adding the words "and [General Partner(s)]"after the word "Seller" in the first line in that section; and

(b) adding the words "or [General Partner(s)]" after the word "Seller" in all other places where the word "Seller" appears in that section.

8. Section 19.2 is amended by replacing the words "the Seller" with the words "the Seller and the [General Partner(s)]" in the first line thereof.

9. The definition of "**Affiliate**" in Appendix 1 is deleted and replaced with the following:

"**Affiliate**" means, with respect to the Seller or [General Partner(s)] any Person directly or indirectly Controlled by, Controlling, or under common Control with, the Seller or [General Partner(s)] and with respect to the Buyer, any Person directly or indirectly Controlled by the Buyer and, if at any time the Buyer is not Controlled, directly or indirectly by the Province of British Columbia, shall include any Person directly or indirectly Controlling, or under common Control with, the Buyer.

10. The definition of "**Bankrupt or Insolvent**" in Appendix 1 is amended by adding the following after the word "Person" in the first line of that definition: "(which in the case of the Seller includes any or all of the Seller or [General Partner(s)])"

11. Subsection (a) of the definition of "Buyer Termination Event" in Appendix 1 is deleted and replaced with the following:

    "(a) any one of the Seller or [General Partner(s)] is Bankrupt or Insolvent";

12. The words "the Seller is in material default" in subsection (e) of the definition of "Buyer Termination Event" in Appendix 1 are deleted and replaced with the following:

    "any one or all of the Seller, or [General Partner(s)] is in material default"

13. The definition of "**COD Certificate**" in Appendix 1 is amended by adding the following after the words "officer of":

    "each [General Partner(s)] and".

14. Note to Bidders: The description of the Parties on page 1 of the EPA and the signature block will be amended as necessary to reflect the limited partnership structure.

PART L – INTENTIONALLY DELETED

ISSUE: **Interconnection Agreement**

REFERENCE: **Application, page 8, PDF page 11**

QUOTE: "The Project will also include upgrades as required to connect the THELP's Plant to the YIS (defined in the EPA as "Buyer-AEY System" and "Buyer-AEY System Upgrades"). Final scoping for these upgrades (with planning level cost estimates) is to be included in the Buyer-AEY System Interconnection Study Report that is currently being concluded as part of the Interconnection Agreement between THELP, YEC and AEY."

QUESTION:

a) When is the Buyer-AEY System Interconnection Study Report due, and when will those costs be known?

b) Is there a cost threshold for this part of the project at which the project will not be viable or otherwise not proceed?

c) From the Yukon/BC border to Jakes Corner, how many potential electricity users will connect to the system?

d) Are those users customers of THELP or YEC?

e) What First Nation settlement lands and traditional territories would be affect b [sic] the Atlin-Jakes Corner infrastructure, and what is the extent of consultation/accommodation to date?

ANSWER:

(a)

The Buyer-AEY System Interconnection Study report forms part of the Interconnection Agreement. The Condition Precedent date for the Interconnection Agreement to be executed has been extended to March 31, 2022. Please see response to YUB-YEC-1-9(a) for current information on system upgrades and related cost estimates.

(b)

No cost threshold has been specified by THELP for these YEC and AEY system upgrades.

(c) and (d)

No electricity users will connect to the system from the line to be developed and owned by THELP between the Yukon/BC border to Jakes Corner.

(e)

The THELP owned and developed Project facilities in Yukon between the BC/Yukon border and Jakes Corner are in the traditional territory of the Carcross Tagish First Nation, but do not affect any First Nation settlement lands.

Project facilities in British Columbia are in the traditional territory of the Taku River Tlingit First Nation.

THELP is responsible for consultation/ accommodation related to the Project. YEC is not able to advise on the specifics to date regarding these activities.

ISSUE: **Dependable Plant Capacity Tests**

REFERENCE: **Application, page 9, PDF page 12**

QUOTE: "Dependable Plant Capacity Tests at THELP's COD - overall Phase One and Phase Two Dependable Plant Capacity delivered to YEC at the POI, as confirmed by these tests, cannot be less than 8.0 MW and not more than 8.5 MW."

QUESTION:

a) Please explain the significance of the upper limit of 8.5 MW.

ANSWER:

(a)

An upper limit was set to ensure that the plant could be operated during the Peak Winter Period as required to provide dependable capacity, given information on available water availability as reviewed in Tables A1and A2 of the Submission. If for some reason THELP had opportunity to provide a higher delivered capacity, an amendment of this provision would be required – and any such amendment would depend on THELP confirming that the Atlin plant could be operated during the Peak Winter Period as required to provide dependable capacity, given information on water availability.

ISSUE: **Notice of first Peak Winter Period (PWP)**

REFERENCE: **Application, pages 9-10, PDF pages 12-13**

QUOTE: "If THELP is unable to confirm to YEC on or before June 1, 2024 the availability of Dependable Plant Capacity for the first PWP, Section 4.3 of the EPA provides that YEC may proceed to rent diesel generating units for this first PWP and no Dependable Capacity Payment will be payable by YEC to THELP for the first PWP for Dependable Plant Capacity that was already provided by such rented diesels."

QUESTION:

a) How will YEC determine the number of diesel generation units that are required to be rented in the situation referenced in the above quote?

ANSWER:

(a)

Assuming that rented diesel units are 1.8 MW capacity per unit, the number of additional required diesel rental units will be determined by adding the non-available Dependable Plant Capacity under the EPA to the N-1 capacity shortfall that otherwise would be forecast for the PWP and dividing the adjusted shortfall by 1.8 MW (and assuming one rental unit is needed for any resulting fraction).

ISSUE: **Operating rules**

REFERENCE: **Application, page 10, PDF page 13**

QUOTE: "Operating Rules for Seller's Plant (Schedule D of EPA) - require THELP and YEC to coordinate and schedule the delivery of Delivered Energy and Dependable Plant Capacity, subject to provisions affecting operations after each August until the start of the following June that are focused on maximizing hydro storage and its use at YEC's direction for dependable capacity during the PWP while recognizing constraints on changes to winter flows in the 7.8 km power canal due to ice conditions and/or water availability."

QUESTION:

a) Please provide the details and principles YEC will use in determining its merit order for dispatching generation.

b) Where will the Atlin hydro expansion project's electricity be placed in the merit order?

ANSWER:

(a) and (b)

IPP contracts are take-or-pay arrangements; therefore, IPP contracts are dispatched first in the generation stacking order, followed by YEC hydro and thermal assets. Note that the Atlin plant is intended to be shut down for the summer months, unless YEC specifically requests summer energy (which would only happen when thermal generation was otherwise expected on the YIS).

ISSUE: **Commercial terms**

REFERENCE: **Application, page 11, PDF page 14**

QUOTE: "2. Payment for Winter Energy that displaces forecast thermal generation: YEC will only pay for winter energy based on its displacement of YEC's forecast thermal fuel generation costs at long-term average renewable sources for the YIS and the Project."
"3. Delivery of all Winter Energy available: while YEC will only pay for winter energy that displaces LTA forecast thermal generation, YEC will take delivery each winter season (Sep-May) of all available energy that the Project is able to generate."
"4. Thermal Benchmark Pricing: the 2024 benchmark prices paid under the EPA are $0.19/kWh for energy that displaces thermal generation (based on blended thermal generation LNG and diesel fuel costs) and $200/kW per year for the levelized cost of capacity (capital and non-fuel O&M) of permanent new greenfield thermal generation assets. Benchmark prices after 2024 are assumed to escalate at 50% of CPI for energy and 100% of CPI for dependable capacity."
"5. Payment for Capacity: rather than paying for actual dependable capacity provided by the Project, YEC will pay for Dependable Plant Capacity Committed over each Peak Winter Period, based on the outcome of a capacity test completed each December at the beginning of each winter period. A mechanism is included for YEC to recoup any shortfalls in actual dependable capacity delivered each winter period through deductions from the additional revenue opportunities/upside opportunities for THELP (see item 7 below)."

QUESTION:

a) In paragraph 2 of the above quote, explain in detail what is meant by "forecast thermal fuel generation costs at long-term average renewable sources" and how it applies in the context of the quote.

b) How is the thermal displacement amount determined?

c) What happens if thermal fuel generation costs are lower than LTA?

d) What happens if thermal fuel generation costs are higher than LTA?

e) In paragraph 3 of the above quote, what are the implications of this provision relative to the amount of thermal generation that YEC would otherwise require during the winter months?

f) In paragraph 3 of the above quote, does the term “Delivery of all Winter Energy” create a situation where YEC will spill water at its own hydro facilities without generating electricity because it is taking energy based on the Atlin project?

g) Is the result that any energy delivered in excess of LTA forecast thermal generation will effectively be delivered at no cost?

h) In paragraph 4 of the quote above, does the blended LNG and diesel fuel costs for generation closely reflect the actual costs for usage of those generation sources?

i) Please file any existing documents relating to the costing model for permanent new greenfield thermal generation assets, including any form of business case analysis, including comparison with rented diesel generators.

j) Show detailed calculations of how the $0.19/kWh and $200/kW were derived. In the response, list all assumptions made in the calculations.

k) Why are benchmark prices assumed to escalate instead of relying on previous year escalation rates?

l) Is capacity considered a fixed cost? Please explain.

m) If capacity is considered a fixed cost, why is it escalated by CPI?

n) Explain why committed capacity is used and not actual capacity. Please explain why committed capacity is preferrable to actual capacity given, for example, that price and revenue would be more accurate using actual capacity.

o) How does the use of committed capacity benefit both YEC and Yukon ratepayers?

p) Does the mechanism in paragraph 5 result in any actual cash recovery from THELP (or deferral of YEC payments to THELP), and if so, what length of time would it take to recover any shortfalls?

ANSWER:

(a) through (p)

The question focuses on four specific "key principles" relevant to YEC as purchaser, as noted in Section 3.4.1 of the Submission. The principles guided the negotiation of the EPA commercial terms – however, specific questions as posed in this IR regarding EPA commercial terms require review of the EPA terms. The following response accordingly addresses the applicable EPA terms.

Energy Price and Payment for Delivered Energy during Winter Period

Questions (a) through (h) as well as (j and k) address principles and terms for the EPA energy price for delivered energy during the Winter Period.

Overall, in Principle 2 YEC required that EPA energy prices for winter period delivered energy be based on YEC forecast thermal fuel cost savings as assessed at long-term average (LTA) conditions for both the Atlin delivered energy and the other forecast YIS renewable generation sources.

In order to determine the required YEC thermal fuel cost savings, consistency is required with OIC 2021/16 direction that YEC's forecast fuel costs must be based on long term average renewable generation when setting YEC rates – and that variances in actual thermal generation from LTA thermal generation are to be addressed by a low water deferral account. In summary, YEC costs and rates for thermal generation are based on LTA renewable generation sources.

The forecast approach is also necessary to set EPA prices that will provide the Seller sufficient certainty on revenue to prove financial viability, i.e. this certainty is required now to ensure a "bankable" project.

Forecast thermal displacement volumes and costs (2024$) for 2024 load forecast and 2035 load forecast, at LTA Atlin deliveries and low water year deliveries, are provided in Table A3-1 of YEC's Submission. The volume of thermal displacement is calculated by modelling the YIS system using YECSIM to simulate thermal generation both with and without Atlin under 38 water years for 2024 and 2035 YIS forecast loads. The Table A3-1

process is summarized below using as an example Table A3-1 columns A and B dealing with the 2024 YIS load forecast:

- In Table A3-1 for the 2024 load forecast, the model estimates:
  - in column A that LTA winter deliveries of 30.8 GWh result in LTA thermal displacement of 19.583 GWh (displacement at 63.5% of EPA deliveries); and
  - In column B that low water year (i.e., firm) winter deliveries of 25.2 GWh result in LTA thermal displacement of 17.450 GWh (displacement at 69.2% of EPA deliveries).

- The estimated ratio is then applied in each column to the YEC forecast blended fuel cost of 19 cents per kWh to get (row 10) the EPA winter price of 12.1 cents/kWh for LTA deliveries and 13.2 cents/kWh for low water year (firm) deliveries.

- The EPA provides the "Firm" energy price (13.2 cents per kWh in column B) for the first 25.2 GWh delivered during winter in each calendar year.

- A "Non-firm" energy price (7.2 cents per kWh) is provided for the balance of the winter energy delivered in each calendar year (see Table A3-2, column A at row 11 for determination of this price – it is based on the LTA energy deliveries less the firm energy deliveries).

- Based on the assumptions as presented, YEC believes that this approach effectively ensures, within a reasonable range, that the utility will not pay for energy that does not offset forecast thermal displacement.

Based on these assessments, firm and non-firm EPA winter energy prices determination is provided in detail in Table A3-2 for two EPA time periods (2024-2034, and 2035 to the end of the EPA term). These 2024$ prices apply throughout the 40-year EPA term, subject (as is the case for SOP IPP prices) to annual escalation at 50% of CPI.

The response to YUB-YEC-1-13(a) provides the detailed calculations and assumptions regarding the (2024$) $0.19/kWh blend fuel price assumed for 2024 thermal energy displacement cost saving estimates. The 90%/10% assumed mix of LNG and diesel generation reflects YEC assumptions to date for GRA filings and is intended to reflect

reasonably expected LTA thermal generation rather than actual generation in any specific year. Escalation of this forecast blend fuel energy price after 2024 at 50% of CPI reflects the same approach applicable to the SOP IPP price escalations.

Under Principle 3, YEC accepts that they will purchase all energy delivered during the Winter Period. The above Table A3-1 analysis shows how the EPA energy prices with this requirement are based on forecast LTA thermal displacement, taking into account purchased deliveries that do not displace thermal generation and increase water spill at YEC hydro facilities. See also YUB-YEC-1-11 and YUB-YEC-1-12 for additional analysis.

When coupled with the need to set EPA prices based on forecasts, there is cost risk created under Principle 3 because actual conditions will in all likelihood vary from the assumed forecasts. This risk is unlikely to result in material impact on YEC costs as supported in detail in Section 4.3 of YEC's Submission (see Operations, subsection 1 on Delivered Electricity at page 28 of the Submission). This conclusion reflects the ability to adjust YEC thermal generation in response to changes in Atlin deliveries, and the setting of the EPA price based on forecast thermal generation displaced (with firm and non-firm EPA prices that tend to reduce the cost impact of variances in EPA deliveries relative to the Atlin low water year).

Another risk is related to YIS loads, other renewable energy resources or fuel costs for thermal generation being different than assumes for setting EPA energy prices. These YIS forecast condition risks affect any new YEC resource commitment made for long-term energy generation supplies. Although such variances are likely, YEC's Submission (based on analysis provided at pages 28-29) that these risks only affect net YEC costs for the EPA relative to thermal energy generation, and remain reasonable in the context of YIS resource planning.

Dependable Capacity Price and Payment for PWP

Questions (i) through (p) address principles and terms for the EPA capacity price for dependable capacity provided during a Peak Winter Period (PWP).

The assumptions and references for the $200/kW (2024$) EPA capacity price determination based on levelized cost of capacity (LCOC) for new greenfield diesel are reviewed in detail in response to YUB-YEC-1-13(a). As reviewed in that response, the Board in its report on the BESS Project noted that rented diesels would not be a reliable

way of closing the capacity shortfall gap. Rented diesel costs were therefore not considered in the setting of the EPA capacity price.

The LCOC cost benchmarks referenced for new greenfield diesel include capital and non-fuel O&M costs (i.e., fuel costs are excluded). In the case of an actual new diesel plant, once built and in-service the capital cost would be "fixed" and added to YEC rate base with annual depreciation and return on rate base expenses added to YEC annual costs – annual non-fuel operating costs, however, would vary and normally escalate over the years of operation. In contrast to such actual annual cost impacts from a new diesel plant, the LCOC benchmark established one present value amount per kW-yr for year 1 of operation to reflect estimated "real" (i.e., absent inflation) capital and non-fuel O&M over the life, and then assumes that this amount escalates at inflation over the project life.

The resulting LCOC amount per KW-yr was estimated starting in 2019 in the benchmark, and the estimate assumed escalation of this benchmark at CPI throughout the assumed life of the facility (as well as escalation as needed to adjust for an in-service date later than 2019). These factors explain why the EPA capacity price for 2024 assumed 2%/yr inflation escalation from 2019 to 2024, and also provided for ongoing escalation at CPI during the EPA term.

The concept of Dependable Plant Capacity Committed for determining initial payments was adopted as a result of negotiation to address the following considerations needed to allow the EPA to be concluded:

1. **Seller Financial Risk -** THELP required a firm capacity revenue amount for each year to assist in securing its financing, and was not prepared to proceed with these initial payments being subject to variance based on actual performance. THELP did agree, however, to the December capacity test for each year to confirm Dependable Plant Capacity Committed for each PWP based on this test. This measure addressed basic risks related to Seller Plant conditions over time.

2. **Operational Risk** - YEC's review of available water (Tables A1 and A2 of Submission) as well as the EPA Operating Rules confirmed expected ability under all likely water conditions to secure the needed dependable capacity during the PWP. During a PWP it is possible that issues with the ice cover of the power canal or other brief disruptions affecting THELP's Plant may result in short term disruptions to the delivery of dependable capacity. Such disruptions are not

expected to occur on any frequent basis, and would be unlikely to affect overall YIS service reliability unless they are concurrent with an N-1 event during a cold weather period.

In order to proceed, YEC secured the Dependable Capacity Excess Payment (DCEP) mechanism to recover excess Dependable Capacity Payments (DCP) due to shortfalls in actual dependable capacity delivered each PWP. Recoveries are contingent on THELP being eligible for additional payments in future years beyond the EPA prices – but YEC recoveries are to occur before any THELP additional payments would be made for higher-than-forecast loads after 2034 or any carbon tax charges applicable to YEC.

In summary, the use of committed capacity enabled all parties to proceed with work to advance the Project in order to secure the forecast benefits for both YEC (and ratepayers) and THELP.

The mechanism in Principle 5 in the referenced quote would reduce (rather than defer) YEC cash payments to THELP. YEC is not able to provide any assessments of time requirements, beyond noting that recoveries related to Additional Payments (linked to Added Load on the grid) cannot occur before 2035.

ISSUE: **Buyer-AEY System Constraint**

REFERENCE: **Application, page 12, PDF page 15**

QUOTE: "Buyer-AEY System Constraint - YEC will have no liability for a Buyer-AEY System Constraint, except for a Non-Permitted System Constraint as set out in Section 6.5 of the EPA, i.e., a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and which is not caused by (a) Buyer-AEY Planned Outage, or (b) THELP, THELP's Plant, or anything on THELP's side of the POI. If a Non-Permitted System Constraint occurs (and no exemption specified in Section 6.5 applies), YEC will pay THELP (for each such impacted month) for the Monthly Constraint Energy calculated for the relevant month under Schedule F of the EPA."

QUESTION:

a) Please provide further explanation of when YEC will not be responsible for payment in the Buyer-AEY System Constraint in Article 6. In your response, provide a numerical example of how the Monthly Constraint Energy will be calculated.

b) In what circumstances will YEC pay for unplanned outages in THELP facilities through the Monthly Constraint Energy in Schedule F?

c) Would YEC be required to pay for energy not received under the Buyer-AEY System Constraint?

d) Would THELP have any financial liability to YEC for failing to deliver contracted energy due to reasons other than low water conditions? If not, what consequential impacts would there be for Yukon ratepayers?

ANSWER:

(a)

"Monthly Constraint Energy" as defined in Schedule F of the EPA only occurs when YEC is responsible for payment regarding a Non-Permitted System Constraint, i.e., there is no

example possible of how the Monthly Constraint Energy would be calculated when YEC is not responsible for payment in the Buyer-AEY System Constraint in Article 6.

As defined in the EPA, a Buyer-AEY System Constraint "means any disconnection of Seller's Plant from Buyer-AEY System, or any outage, suspension, constraint, or curtailment in the operation of Buyer-AEY System preventing or limiting deliveries of Delivered Energy at the POI or within the Buyer-AEY System or any direction from Buyer to Seller to reduce generation of Seller's Plant as a result of any outage, suspension, constraint, or curtailment in the operation of the Buyer-AEY System."

Section 6.5 provides that Buyer will have no liability for a Buyer-AEY System Constraint (or be in breach of Sections 6.3 or 8.2) unless it is a Non-Permitted System Constraint as defined in Section 6.5. To be a Non-Permitted System Constraint for which YEC will pay the Monthly Constraint Energy calculated for the relevant month under Schedule F, the Buyer-AEY System Constraint must:

- Prevent Seller to deliver Delivered Energy that Seller is permitted to deliver under this EPA.

- Be solely the result of a continuous Buyer-AEY System Constraint which exceeds 30 minutes in duration and is not caused by (a) Buyer-AEY Planned Outage, or (b) Seller, Seller's Plant, or anything on Seller's side of the POI.

- Not be subject to exemptions set out in Section 6.5 when Buyer will not be required to pay for any Monthly Constraint Energy[1].

An example of how the Monthly Constraint Energy will be calculated is provided below, based on an aggregate of the Constraint Shortfall Energy for each Non-Permitted System Constraint event during a month:

1. Assume 2 separate Non-Permitted System Constraint events occur as follows during the PWP month of January when continuous delivery at 8 MW full capacity

[1] Section 6.5 lists four subsection exemptions as subsections "c" through "f", including Force Majeure, any period when Seller's Plant would otherwise not have been operating, any period specified as a Seller's Outage in any Outage Notice or a revised Outage Notice, or when the Non-Permitted System Constraint is the result of the operation of the Seller's Plant in a manner inconsistent with Section 3.2 of the EPA.

has been planned throughout each day during each week pursuant to the Operating Rules:

a. Event #1: 1 hour when 8,000 kWh Delivered Energy was expected to be provided; and
b. Event #2: 100 hours when 800,000 kWh Delivered Energy was expected to be provided.

2. Assume that the following reductions in such expected Delivered Energy are reductions that Seller takes, or is reasonably able to take, in response to the Non-Permitted System Constraint events to reduce or shut down water deliveries in the Upper Powerhouse:
    a. Event #1: No such reductions.
    b. Event #2: Determination that in response to the Non-Permitted System Constraint the Seller was able to shut down water deliveries in the Upper Powerhouse after 48 hours (2 days), resulting is a reduction capability of 416,000 kWh = (800,000-48*8000).

3. The Monthly Constraint Energy for January will then equal 392,000 kWh based on the aggregate of the following Constraint Shortall Energy for the two Non-Permitted System Constraint events during the month:
    a. Event #1: Constraint Shortfall Energy equals 8,000 kWh = (8000-0)
    b. Event #2: Constraint Shortfall Energy equals 384,000 kWh = (800,000-416,000).

(b)

There are no circumstances related to Monthly Constraint Energy when YEC will pay for unplanned outages in THELP facilities. As reviewed in response to “a” above, Section 6.5 of the EPA specifically excludes consideration of events on the Seller’s side of the POI or the result of operation of Seller’s Plant in a manner inconsistent with Section 3.2 of the EPA.

(c)

Yes, provided that such energy qualifies as Monthly Constraint Energy (see “a” above - the example shows 392,000 kWh that would need to be paid for by YEC).

(d)

The question asks about “contracted energy”. Overall, the EPA does not generally impose financial liabilities (other than reduced payments for the reduced energy deliveries) on THELP for failure to deliver expected energy deliveries for reasons other than low water conditions.[2] As reviewed in section 4.3 of YEC’s Submission (under Operations, Delivered Energy), the risk of a material impact on YEC costs, customer rates or reliability of service to customers from actual EPA delivered energy being lower than expected deliveries is not considered likely.

[2] This response does not preclude potential financial liabilities related to a breach of EPA terms and conditions that result in reduced energy deliveries.

ISSUE: **Winter delivered energy**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Also, provisions for added payments related to winter delivered energy (subject to any reductions under Section 8.3 of the EPA) for the following possibilities where YEC and THELP will share added thermal cost saving benefits:
• Additional Payments starting in 2035 if there is Added Load on the YIS, i.e., load in excess of that assumed [with no industrial load] to determine the 2035 energy price.
• Carbon Charge Saving Payment if YUB approves a carbon charge in future to be included in customer rates."

QUESTION:

a) Please provide further details on what carbon charge YEC is contemplating and why a term in this agreement was required.

ANSWER:

(a)

A term in the EPA was requested by THELP to address the possible added value of Atlin energy deliveries (based on resulting YEC cost savings for displaced thermal generation) in the event that the YUB approves inclusion in YEC customer rates of a Carbon Charge related to YEC thermal generation.

The provision contemplates a carbon tax or other form of carbon charge being imposed on YEC fossil fuel use for its thermal (LNG and diesel) generation.

ISSUE: **Dependable Capacity Payment**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Dependable Capacity Payment (DCP): the DCP is the payment by YEC to THELP, based only on Dependable Plant Capacity Committed (DPCC) as provided for in annual test in December, and a Dependable Capacity Price of $200/KW per year16 (2024$) as escalated at CPI after 2024."

QUESTION:

a) Why is inflation being applied? How do fixed or sunk costs factor into the application of CPI after 2024?

ANSWER:

(a)

The application of inflation to the EPA capacity price (DCP) over the life of the EPA is necessary to ensure lifecycle costs (i.e., present value costs over the 40-year project life) are the same whether YEC owns the equivalent diesel asset or buys the capacity through this IPP.

The DCP is based on the LCOC benchmark is a levelized cost for an equivalent owned asset. This benchmark sets the EPA capacity price based on ratepayer costs if YEC developed a greenfield diesel plant – including ratepayer costs over the diesel plant project life for depreciation, return on rate base and non-fuel O&M costs. The LCOC benchmark provides a price per KW-yr in 2024$ (after escalation from 2019$ used for the earlier studies). The LCOC annual levelized cost for the diesel plant is lowest in year 1 and escalates at inflation over the 40-year life – this differs from normal rate base revenue requirement determinations for the same diesel plant non-fuel costs which are highest in year 1 (due to rate base return impact) and then decline over the 40-year life. However, the present value of these costs at the start of project operation is the same under the LCOC approach and the rate base approach, assuming YEC's weighted average cost of capital is used as the discount rate.

The LCOC when calculated includes capital costs per kW (i.e., sunk costs) as well as non-fuel O&M costs per kW that are assumed to escalate annually at inflation. This levelized cost assumes YEC ownership of the new diesel plant over a 40 year life. The LCOC converts the “sunk costs” for capital into a 2024$ levelized cost per kW-yr for the 40 year life that recovers depreciation and a rate base return assuming YEC’s weighted average cost of capital (WACC). This levelized cost in 2024$ in year 1 of operation yields an amount per kW that escalates at inflation over the 40 year assumed thermal plant life in order to yield the present value initial sunk costs plus the applicable YEC WACC (debt and equity return) on this rate base.

In summary, the LCOC benchmark assumes inflation at CPI to adjust the price for each subsequent year during the thermal plant life (or in this case during the term of the EPA). Therefore, in order to apply this benchmark to setting the EPA capacity price, it is necessary to escalate the price each year by CPI.

Please see response to YUB-YEC-1-24 (section on Dependable Capacity Price and Payment for PWP) for a more detailed response.

ISSUE: **Dependable Capacity Excess Payment**

REFERENCE: **Application, page 13, PDF page 16**

QUOTE: "Dependable Capacity Excess Payment (DCEP) Account as per Section 8.3 of EPA"

QUESTION:

a) Please provide further explanation of this account and how this account will operate.

b) Will regulatory approval from the Board be required for recovery of costs or payment of refunds for payments under the DCEP Account? If not, how will YEC customers be protected from adjustments of payments that are required under Section 8.3 of the EPA?

ANSWER:

(a)

A more detailed explanation of the DCEP Account is provided in Appendix B, section 4.1.2, subsection 3(b) (Dependable Capacity Excess Payment (DCSP). A sample calculation to show how this account is adjusted is provided in Schedule G of the EPA and a tabular summary of the example is provided in Tables A4-1 and A4-2 of YEC's Submission. See also response to YUB-YEC-1-24 (section on capacity price).

(b)

The DCEP Account only allows for YEC to recover overpayments already made to THELP, i.e., there is no ability for THELP to access this Account to secure any added payments from YEC.

The EPA does not require or provide for any YUB approval prior to YEC use of this Account to recover amounts from THELP (through allowed reductions in future amounts that YEC would otherwise be required to pay to THELP). As noted above, any YEC use

of this Account would be for the ultimate benefit of YEC customers, subject to YUB review and approval of any required mechanism to allow the resulting cost savings to be reflected in customer rates.

ISSUE: **YIS system upgrades**

REFERENCE: **Application, page 15, PDF page 18**

QUOTE: "… the only utility assets being developed by YEC/AEY pursuant to the EPA are YIS system upgrades that are to be fully funded by the Project at no cost risk to the utilities."

QUESTION:

a) To YEC's knowledge, do AEY system upgrades include a change from the existing 38 kV line to a 69 kV line? Please provide evidentiary support as part of the response.

ANSWER:

(a)

The AEY system upgrades for the Atlin EPA retain the existing AEY line voltage at 34.5 kV. Please see response to YUB-YEC-1-9(a) for additional information on the AEY system upgrades.

ISSUE: **Thermal displacement**

REFERENCE: **Application, page 15, PDF page 18**

QUOTE: "The capability of the Project during the initial 40-year EPA operating term to displace thermal generation capacity and energy otherwise expected to be required on the YIS to supply forecast electric load."

QUESTION:

a) Why was a term of 40 years chosen? In your response, please provide what YEC considers is a standard term (in years) of an EPA based on past YEC projects or other information.

b) Will this project displace any existing hydro facilities on the YIS, for any periods throughout the year?

ANSWER:

(a)

The EPA term of 40 years was selected based on the renewable source (hydro). The Yukon SOP EPA [see YUB-YEC-1-9(a), Attachment 1, Schedule B] provides for a term of up to 40 years for a hydro clean energy source, and is understood to reflect practice for IPP agreements in British Columbia.

(b)

Energy delivered from the Atlin EPA will result at times in increased spill at existing hydro facilities on the YIS. This outcome is expected to occur with all currently planned SOP EPAs connecting to the YIS. The Atlin EPA has adjusted the EPA energy price to take into account the expected degree of thermal generation displacement versus hydro generation displacement.

See response to YUB-YEC-1-11 and YUB-YEC-1-12 for more detailed review of how EPA energy prices were established in this regard.

ISSUE:

REFERENCE: **Application, page 16, PDF page 19**

QUOTE: "The analysis below references certain sources that were reviewed by the Board in YEC's recent Part 3 application regarding the Battery Energy Storage System (BESS project) and YEC's 2021 General Rate Application (2021 GRA). These sources include:

…

- Goals outlined in Yukon government's draft 'Our Clean Future: A Yukon strategy for climate change, energy and a green economy'
- Relevant Order-in-Council (OIC) directions to the YUB affecting costs to be included in YEC's rates as approved by the Board."

QUESTION:

a) Please explain the applicability of OIC 2021/16 to this project.

b) Provide a copy of the draft or final report "Our Clean Future: A Yukon strategy for climate change, energy and a green economy" that is referred to in the above quote.

c) Page 21 of the Application, PDF page 24, refers to the Clean Energy Act. How should the Board assess the relevance of this act in making its recommendations to the Minister when the act has not been enacted, i.e., consultations recently closed in January 2022?

ANSWER:

(a)

As stated on page 16 and in footnote 16 of the Submission – OIC 2021/16 is applicable insofar as it relates to the use of long term average (LTA) annual renewable source availability (which includes IPP renewable sources such as Atlin) for forecasting renewable generation available to contribute to meeting forecast customer requirements when setting YEC rates.

This IPP direction established the relevance and basis for assessing LTA thermal displacement expected to result from the Atlin EPA, and its effect on YEC costs to be used when the YUB sets YEC rates.

(b)

Please see Attachment 1 (final report) and Attachment 2 (draft report) to this response.

(c)

The Yukon government has indicated its intention in Our Clean Energy Future to bring into force the Clean Energy Act – and Yukon Energy understands that this would require YEC to meet a 93% Renewable Portfolio Standard. As noted in the question, public consultations on this Act closed in January 2022

While the specific legislation has not yet been enacted, the expected requirement for Yukon Energy to meet the standards outlined in the proposed Act (and potential consequences for Yukon Energy should it fail to meet standards outlined in the proposed Act) can inform the consideration of the public need for the Atlin Project EPA, and the basis for the EPA as a preferred alternative for meeting YIS capacity and energy requirements, when the Board advises the Minister.



Our Clean Future

A Yukon strategy for climate change, energy and a green economy

Yukon



All photos © Government of Yukon, unless otherwise noted.
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On the cover: Old Crow solar project. Photo: Government of Yukon/Bree Josie

Caribou near Dempster Highway. Photo: Robert Postma.

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MESSAGE FROM THE PREMIER



Climate change represents the biggest challenge of our generation.

Yukoners have told us loud and clear that they care passionately about climate change and want to see Yukon doing our part. Our government listened.

We have established an ambitious and achievable greenhouse gas reduction target for Yukon and laid out concrete steps we will take to mitigate and adapt to the impacts of climate change. We will integrate these efforts with building a green economy and an energy sector increasingly focussed on renewable sources.

Our Clean Future is the tangible result. We developed shared priorities for climate action in partnership with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities. We heard from the public and members of stakeholder and industry groups. Thank you to all who provided valuable ideas and feedback. This Yukon-made strategy sets clear direction for a strong and resilient future.

Rising to the challenge of climate change requires participation from all Yukoners. Over the past few months, Yukoners have demonstrated what we are willing to do to keep our families, friends and communities safe. In the face of the COVID-19 pandemic, we have had to innovate and adapt in terms of how we connect with loved ones, the ways in which we work and operate businesses, and how we continue to look after one another as a small, closely connected territory.

We are proud of the strength and resiliency demonstrated by Yukoners as we have all adapted to the demands of COVID-19. We call on Yukoners to continue to be leaders as we make further changes to address climate change. As your government, we will be with you every step of the way, from rebates and financial support to help you buy low-carbon technologies to leading by example through improvements to our own buildings and vehicle fleet.

We also look forward to continued collaboration with Yukon First Nations and transboundary Indigenous groups on climate action, as the Council of Yukon First Nations and the Assembly of First Nations-Yukon Region spearhead the development of a Yukon First Nations climate change action plan. We recognize the threat that climate change poses to Indigenous cultures, ways of life and wellbeing and will continue to support Indigenous-led climate action.

As governments around the world tackle the economic impacts of the COVID-19 pandemic, it is critical that economic stimulus efforts align with our climate change commitments. Otherwise, we risk making one challenge worse through our response to another. In partnership with the Government of Canada, we will invest over $200 million over the next four years in renewable energy generation, energy efficiency, clean transportation and adaptation to the impacts of climate change. These actions will position us for long-term sustainability and self-sufficiency while helping Yukoners recover from the financial impacts of the COVID-19 pandemic. Rather than returning to normal, we will take this opportunity to rebuild and refocus for a clean future.

The Honourable Sandy Silver
Premier of Yukon

MESSAGES FROM PARTNERS

Climate change is a threat to the Vuntut Gwitchin, to the lands, water and animals we rely on for sustenance and to practice our culture. Reducing our dependency on fossil fuels though innovative clean energy projects and a green economy that provides sustainable jobs for our youth are opportunities that build community resiliency, energy security and a better future for our children.

Vuntut Gwitchin Government Chief
Dana Tizya-Tramm

White River First Nation is pleased to be a part this initiative to address climate change in the Yukon. Our members are observing changes out on the land and they are happening much quicker than expected. Our community is thrilled to see our 1.5MW solar field constructed in Beaver Creek this summer to offset our use of diesel in the community. By taking action on climate change now, we are lessening the impacts to the land and water that future generations will have to adapt to.

White River First Nation Chief
Angela Demit

Municipal governments have the flexibility not available to larger governments to quickly make changes and find opportunities for climate-change adaptation and mitigation. The City of Dawson is excited to be part of this work and making climate-friendly changes to our own operations.

City of Dawson Mayor
Wayne Potoroka

The City of Whitehorse is aware of the consequences of climate change and the strong political will required to deal with this global challenge. As a result, we declared a climate change emergency on Sept. 23rd, and we continue to closely monitor the risks to our City's residents and businesses. The City is committed to taking action on climate change by working to reduce corporate and community emissions, as well as adopting climate change adaptation initiatives.

City of Whitehorse
Mayor Dan Curtis

As long standing stewards of our traditional territory that spans Yukon, Northwest Territories and British Columbia, Acho Dene Koe First Nation (ADKFN) will continue to support actions and strategies that balance economic opportunity with the preservation of our lands and waters. Through implementation of the strategy, we look forward to working with the Yukon Government and our First Nation partners to maintain our ability to engage in traditional activities and supply more of what we eat through local harvesting and food production.

Acho Dene Koe First Nation Chief
Gene Hope

The Inuvialuit have an interconnected and enduring relationship to the Yukon North Slope. This area and its adjacent seas have supported our culture and sense of identity for a very long time. As such, the preservation of this land and the rest of the Inuvialuit Settlement Region (ISR) is keenly important. We welcome effective partnerships across northern Canada to advance collaborative climate action and sustained traditional livelihoods.

Inuvialuit Regional Corporation Chair and
Chief Executive Officer
Duane Smith

We live in a world that is rapidly changing. Climate change is threatening ecosystems, subsistence harvesting, infrastructure, leisure activities and many other aspects of our lives.

Yukon's population is growing, along with our need for reliable, affordable and renewable energy to continue to power our lives, our work and our economy. New economic opportunities are emerging in the sustainable, green economy.

Across the North, we have a long history of coping with and adapting to changing, and sometimes harsh, conditions. First Nations and Indigenous identities and ways of life are intimately connected with the land, rivers and mountains that are home. Generation after generation, Indigenous people have built and passed along knowledge, skills and values shaped in part by the changing patterns of the landscape.

Our history of adaptation and resilience provides a strong foundation as we work together to address climate change. However, many of the changes we are experiencing now are unprecedented in terms of scope and speed, making it more important than ever to come together to share our collective knowledge and experiences to take action for a healthy future for our children and grandchildren.

In fall 2019, the Government of Yukon declared a climate change emergency, following in the footsteps of the City of Whitehorse and the Vuntut Gwitchin First Nation. In February 2020, Yukon First Nations declared a climate emergency due to the threat that climate change poses to the culture and way of life of First Nations people. In the declaration, Yukon First Nations call on all governments, corporations and individuals to act in the best interests of the planet and future generations as they come together to address climate change.

Outside Yukon, countries around the world have committed through the Paris Agreement to keep global temperature rise below two degrees Celsius and respond to the impacts of climate change. In Canada, the federal government, provinces, territories and communities, are taking action to reduce greenhouse gas emissions and build greener economies powered by clean energy that will be more resilient and sustainable. Yukon will be part of this national and global shift, and we will continue to work collaboratively with governments around the world to take collective action on this global issue.

OVERVIEW OF THE STRATEGY



Mount Decoeli.

The Government of Yukon developed *Our Clean Future* in partnership with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities over the course of three years. Over that time, the partner group gathered four times to establish a vision and values for *Our Clean Future* and to prioritize the areas we should focus on over the next 10 years to respond to the climate emergency. As a result of this collaborative process, the strategy reflects multiple perspectives, worldviews and ideas.

In order to reach each of the objectives that we have set for the next 10 years, all Yukoners need to take part. *Our Clean Future* lays out the specific, tangible actions that the Government of Yukon will take to work toward these objectives. Several Indigenous and municipal partners have also put forward actions they will take to continue to lead the way toward a clean future.

Our Clean Future focuses on the next 10 years until 2030, even though we know that we need to continue to act far past 2030. In fact, our efforts on climate change will need to get more significant as time passes. However, by focusing on the next 10 years, we are holding ourselves accountable to quickly and urgently take the steps that are needed now to begin addressing the climate emergency. This near-term focus can be complemented by a longer-term, multi-generational perspective of climate change often taken by Indigenous people that recognizes how our actions will support environmental stewardship and healthy communities for generations to come.

Our Clean Future has been informed by ideas and feedback we received from the public and stakeholders during two rounds of engagement in fall 2018 and 2019. For more information, please refer to the What We Heard reports available on EngageYukon.ca.

VISION AND VALUES

Our vision is to come together as leaders to address climate change by building thriving, resilient communities powered by renewable energy and supported by a sustainable green economy that protects and restores our natural environment.

The steps that we take to achieve our collective vision will be shaped by the following core values established by the Government of Yukon with participating Yukon First Nations, transboundary Indigenous groups and Yukon municipalities:

For all Yukoners

We are building a brighter future for the collective, long-term benefit of all Yukoners today and for those to come, inclusive of ethnicity, culture, language, gender, sexuality, age, ability, education, income and other identity factors.

Empower everyone

We will foster partnerships, collaboration, information-sharing and capacity-building to empower all governments, organizations, businesses and individuals to take action.

Raise awareness

All Yukoners should be aware of climate change, energy and the economy and how they can contribute to building a more sustainable, resilient future.

Be accountable

We will outline specific, measurable and time-bound actions to achieve our collective goals, along with the necessary human and financial resources to implement and monitor them and regular reporting on progress.

Support reconciliation

We will support reconciliation by protecting the unique spiritual relationship that Indigenous people have with the land through strong action on climate change. We will also support self-determination and strengthen relationships between Indigenous and non-Indigenous governments, organizations and individuals through open communication and partnerships.

Respect our natural environment

We will recognize the inherent value and importance of our natural environment and prioritize solutions that protect, conserve and harness natural capital and ecosystem services.

Make informed decisions

We will make informed decisions that respectfully bring together traditional, scientific and local knowledge and Indigenous ways of knowing, doing and being.

No “one size fits all” approach

Our actions will reflect Yukon’s unique strengths and challenges by supporting community-based projects that make sense in their local context.

GOALS

We will work toward four goals that will help us achieve our vision for a clean future:

1. 

Reduce Yukon's greenhouse gas emissions.

2. 
Ensure Yukoners have access to reliable, affordable and renewable energy.

3. 
Adapt to the impacts of climate change.

4. 
Build a green economy.

Taking action on these four goals will support healthy people, communities and ecosystems. By reducing greenhouse gas emissions and building a green economy that protects and restores the natural environment, we will uphold our joint responsibilities as stewards of the land while supporting sustainable economic wellbeing for future generations. Our actions will also support Yukoners to continue practicing traditional and cultural activities that are being threatened by climate change, supporting physical, mental and spiritual wellbeing.

The following sections describe each goal in more detail and lay out the targets that we will work toward.



The Hart River in winter.

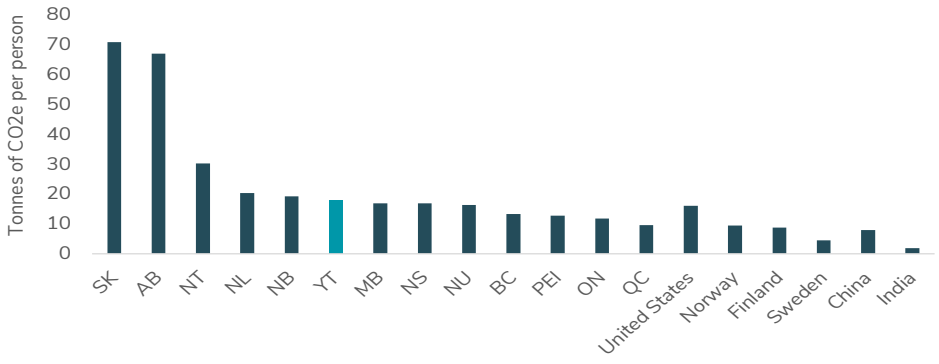
Reducing greenhouse gas emissions

The issue

Climate change is caused by the release of greenhouse gases – like carbon dioxide and methane – primarily from human activities that burn fossil fuels. These activities range from driving vehicles and heating buildings to commercial and industrial processes.

While Yukon's total greenhouse gas emissions are relatively low because of our small population (0.1 per cent of Canada's emissions), our per person emissions of around 18 tonnes per person are the sixth highest in Canada and higher than many other countries. It is important that we do our part to reduce the greenhouse gas emissions that are causing climate change.

Figure 1. Comparison of greenhouse gas emissions per person in Canadian provinces and territories (2017)[1] *and a selection of other countries (2018).*[2]



1 Estimated based on provincial and territorial emissions in Canada's National Inventory Report and population statistics from Statistics Canada.

2 Crippa, M. et al., 2019. Fossil CO2 and GHG emissions of all world countries - 2019 Report. Publications Office of the European Union, Luxembourg, ISBN 978-92-76-11100-9, doi:10.2760/687800, JRC117610.

In Yukon, greenhouse gas emissions mostly come from transportation and heating, with a smaller amount from industry, electricity generation, waste and other areas. Yukon's greenhouse gas emissions are calculated using two main sources of information. The Government of Canada's National Inventory Report, which reports greenhouse gas emissions across the country, is combined with information about fossil fuel sales in Yukon collected by the Yukon Bureau of Statistics to provide the most accurate picture of Yukon's emissions.

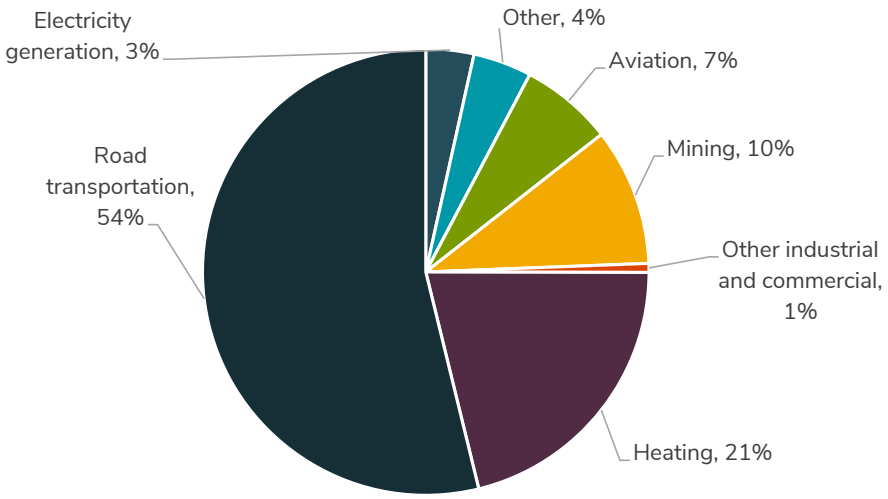


Figure 2. Yukon's sources of greenhouse gas emissions (2017)[3].

Yukon's greenhouse gas emissions only account for emissions that are produced within Yukon's borders. For example, a truck that drives from British Columbia to Yukon to deliver food will produce greenhouse gas emissions in both British Columbia and Yukon. By looking at truck logs that report how many kilometres were driven in Yukon, we can figure out how much of the truck's emissions count toward Yukon's total. Greenhouse gas emissions are tracked and reported on the basis of political borders to avoid double counting when reporting Canadian or global emissions.

3 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.

Our targets

By 2030, we will reduce Yukon's total greenhouse emissions from transportation, heating, electricity generation, other commercial and industrial activities, waste and other areas so that our emissions in these areas are 30 per cent lower than they were in 2010.

This is an ambitious and achievable target that is aligned with Canada's international commitment under the Paris Agreement.

While this greenhouse gas reduction target will ensure we see a decrease in emissions from transportation, heating and other areas, we also need a plan to address greenhouse gas emissions from mining, which were 10 per cent of Yukon's total emissions in 2017.

We will work with industry to set a target for greenhouse gas emissions from placer and quartz mining by the end of 2022 that will see Yukon mines produce fewer emissions of greenhouse gases across their lifecycle for every kilogram or kilotonne of material produced.

This intensity-based target will encourage industry to look for innovative ways to reduce energy use and greenhouse gas emissions from mining, regardless of how many or few mines are in operation at any time.

Reaching these targets by 2030 will put Yukon on the path to net-zero greenhouse gas emissions by 2050 for our entire economy. This long-term target is aligned with the substantial level of greenhouse gas reductions that we know is needed worldwide to avoid catastrophic climate change.

The Yukon-wide greenhouse gas reduction target

Reaching the 30 per cent greenhouse gas reduction target will require extensive modernization to our road transportation and heating systems, which together contribute 75 per cent of Yukon's emissions. It will also require significant diversified investments in more renewable electricity generation, creating local jobs and economic opportunities. By reaching this target, we will inspire others by demonstrating that a remote, northern jurisdiction can achieve a significant reduction in greenhouse gas emissions.

We have learned several lessons since the last time greenhouse gas reduction targets were set for Yukon. In the 2012 Climate Change Action Plan Progress Report, twelve different targets were set for a variety of sectors. While the targets related to greenhouse gas emissions from buildings and electricity generation were met, the other targets were not met or could not be reported on due to a lack of available data.

Since that time, we have made improvements to how we gather and report greenhouse gas emissions data. We are now setting targets that we know we can track through available data. We have also conducted modelling work to help us set a greenhouse gas reduction target that is both ambitious and achievable.

Mining plays a central role in the transition to a green economy. Minerals are vital to low carbon technologies – from batteries to wind turbines, solar panels and electric vehicles. Meeting an emissions intensity target will help Yukon's mining industry sustainably produce the materials needed for the global green economy.

Greenhouse gas reduction modelling

In 2017, the most recent year we have data for, Yukon's greenhouse gas emissions, with the exception of mining, were 624 kilotonnes. This is an increase from 2010 emissions of 592 kilotonnes. Based on modelling, we anticipate that Yukon's emissions, excluding mining emissions, could increase to 678 kilotonnes in 2030 if we do not take action. As a result, to reach our 30 per cent greenhouse gas reduction target by 2030, we estimate that we need to reduce our emissions by 263 kilotonnes.

However, forecasting what Yukon's greenhouse gas emissions could be in 2030 is very challenging. Future emissions depend on several factors, including population growth, the economy, and the success of the actions in this strategy, all of which are hard to predict. This makes it very important to track actual greenhouse gas emissions on a regular basis and be flexible and adaptive in our efforts.

Assuming that we need to reduce greenhouse gas emissions by 263 kilotonnes, we expect that the actions outlined in this strategy will get us three-quarters of the way there. To close this gap, we will update our actions in 2024 based on our progress and new information that has emerged. In 2027, we will complete another update based on the newest information on our progress. As part of tracking our progress, we will expect to see Yukon's greenhouse gas emissions go down to at least 10 per cent below 2010 levels by 2025 in order to reach the 2030 target.

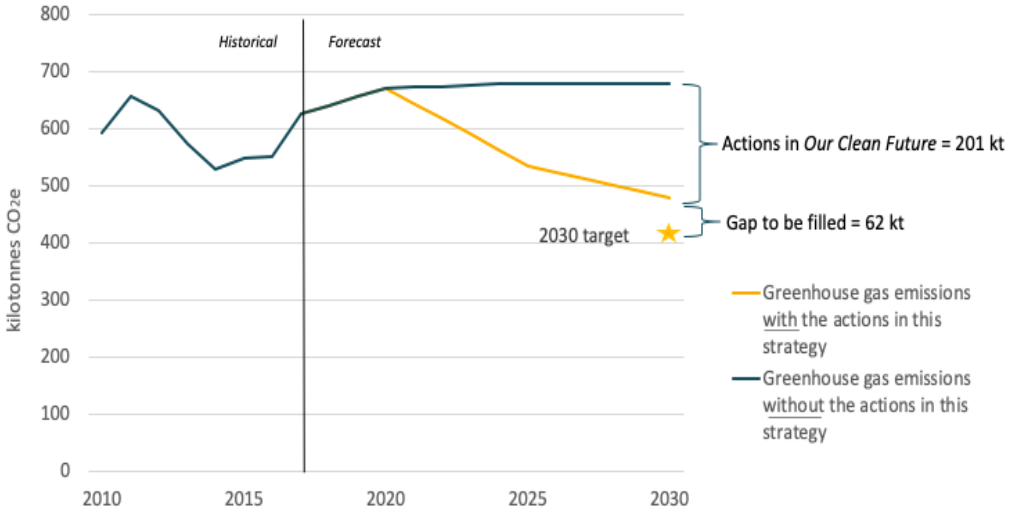


Figure 3. Historical and forecasted non-mining greenhouse gas emissions with and without the actions identified in this strategy.

Anticipated greenhouse gas reductions in 2030 in kilotonnes (kt)

Increasing the use of zero emission vehicles: • Requirements for zero emission vehicles to be 10 per cent of light-duty vehicles sales by 2025 and 30 per cent by 2030. • Rebates for purchasing zero emission vehicles. • Commitment for half of all new cars purchased by the Government of Yukon to be zero emission vehicles.	13 kt
Increasing the use of public and active transportation.	6 kt
Using cleaner fuels for transportation: • Requirement for diesel fuel to be blended with with biodiesel or renewable diesel beginning in 2025. • Requirement for gasoline to be blended with ethanol beginning in 2025.	59 kt 11 kt
Making buildings more energy efficient and switching to renewable heat: • Funding, rebates and low-interest financing for retrofits. • Requiring new buildings to be significantly more energy efficient.	12 kt 5 kt
Conducting energy efficiency retrofits and installing renewable heating systems in Government of Yukon buildings.	8 kt
Using clean electricity: • Requiring 93 per cent of the electricity on the main Yukon grid to come from renewable sources on average. • Reducing the use of fossil fuels for electricity generation in off-grid communities by 30 per cent through community-based renewable energy projects. • Substituting some of the diesel used to generate electricity with clean diesel alternatives like renewable diesel or biodiesel.	79 kt 10 kt 4 kt
Total*	201 kt
GHG reduction needed to reach 30 per cent target	263 kt

*The total does not match the sum of the invidual policies because of policy interactions where two or more policies contribute to the same greenhouse gas reduction.

The mining intensity target

From 2009 to 2017 – the period of time for which we have reliable greenhouse gas emissions data for Yukon – emissions from placer and quartz mining have varied from year-to-year depending on the amount of mining activity in the territory. These annual fluctuations can be seen in Yukon's total greenhouse gas emissions as well, which is the direct outcome of increases or decreases to mining emissions as well as the indirect impact that mining activity has on overall economic activity in the territory. Overall, mining emissions have ranged from 10 to 15 per cent of Yukon's total emissions over this period.

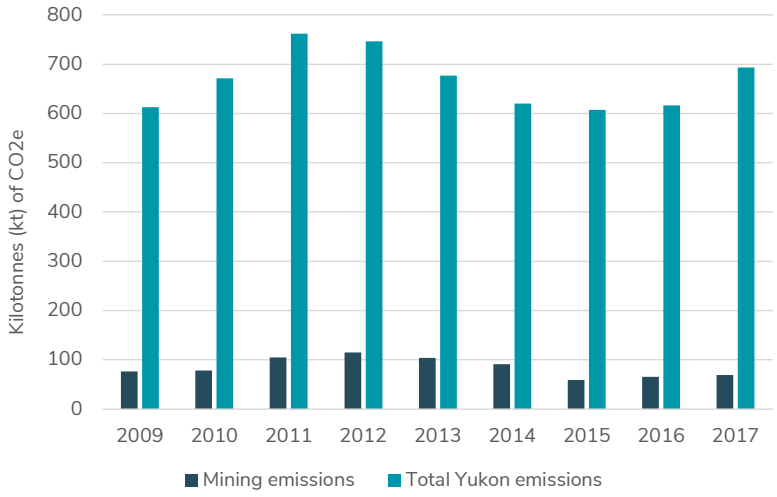


Figure 4. Yukon's total greenhouse gas emissions and the portion of emissions from mining from 2009 to 2017.[4]

The year-to-year variability of Yukon's mining emissions makes it difficult to set a maximum level of greenhouse gas emissions from mining to be reached by a certain date. If mining activity were to decrease, total mining emissions could reach the target without requiring any improvements to how mines operate. If mining activity were to increase, the target could become unachievable.

Unlike an absolute greenhouse gas reduction target, an intensity-based target that establishes a desired level of greenhouse gas emissions per unit of material produced will encourage operational efficiencies regardless of how many or how few mines are in operation at any one time.

In addition, establishing a tailored approach for mining emissions eliminates the possibility for a substantial change in mining activity to skew our efforts to reduce emissions from other parts of Yukon's economy. For example, if mining emissions were part of the Yukon-wide greenhouse gas reduction target, a significant decrease in mining activity could help us to reach the 2030 target without needing to make as many improvements to our transportation and heating systems.

4 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.



Caribou herd.

While a tailored intensity-based approach to mining emissions makes sense for the reasons noted above, it is important to set up a system that works. The Government of Yukon will work with industry to set the mining intensity target, or targets, for placer and quartz mining by 2022. During that time, we will consider challenges like the different types of mining operations in Yukon, how to accurately track placer gold production and how to account for greenhouse gas emissions across the entire mine lifecycle from development through to closure and remediation. These are challenging issues that will take time to think through. We will also assess whether the current actions in *Our Clean Future* are sufficient to reach the target that is set, or whether additional actions need to be taken.

As we do this work, we will keep in mind the intensity-based targets for mining in Canada's Output-Based Pricing System. The Output-Based Pricing System is designed to encourage industrial emitters to innovate and reduce their greenhouse gas emissions while maintaining competitiveness and protecting against carbon leakage. Quartz mines in Yukon may be part of Canada's Output-Based Pricing System depending on their size, which is why it will be important for both intensity-based approaches to be coordinated.

When designing climate policy, it is important to avoid unintentionally creating carbon leakage. Carbon leakage occurs when companies or industries shift their operations to other parts of the world that have less stringent climate policies. The result of carbon leakage is that global greenhouse gas emissions may not go down, or may even increase, depending on the situation.



Power lines running along highway.

Ensuring reliable, affordable and renewable energy

Electricity

The issue

In Yukon, historically we have met over 90 per cent of our electricity needs each year with clean, renewable power because of our large supply of hydroelectricity.[5] As Yukon's economy and communities grow, and as Yukoners increasingly invest in electric vehicles and electric heating technologies, demand for electricity will grow.

All but four of Yukon's communities are connected to the same electrical transmission network, referred to as the Yukon Integrated System or the main electricity grid. Most of the generation and high voltage transmission of electricity on the main grid is managed by the Yukon Energy Corporation, while most distribution is the responsibility of ATCO Electric Yukon. The four communities not connected to the main electricity grid – Beaver Creek, Burwash Landing/Destruction Bay, Watson Lake and Old Crow – are served by four micro-grids that have been primarily powered by diesel generators operated by ATCO Electric Yukon.

5 As demonstrated by annual submissions to the Yukon Utilities Board by the Yukon Energy Corporation and ATCO Electric Yukon.



Figure 5. Yukon's electrical generation facilities and transmission lines. Figure provided by the Yukon Energy Corporation.

Our targets

For Yukon's main electricity grid, we will aspire to see 97 per cent of the electricity we use come from renewable sources by 2030.

This includes electricity used by mines that are connected to the grid. This target is consistent with the bold vision in the Yukon Energy Corporation's 10-year renewable electricity plan, released in draft form in January 2020.

For the communities that are not connected to the main electricity grid, we will reduce diesel use for electricity generation by 30 per cent by 2030, compared to 2010.

We will also substitute some of the diesel fuel that continues to be used with clean alternatives like biodiesel and renewable diesel.

To make sure the lights turn on when we need them and that we are able to heat our homes – even on the coldest days of winter – we will also have the necessary backup power on hand. Today, fossil fuels like diesel and natural gas are best suited for backup power because they are quick and reliable. Over time, technological improvements and efforts to be more energy efficient will reduce the amount of fossil fuels we need to have as backup energy.

How we will meet them

To meet Yukon's renewable electricity targets, we need to invest in more electricity generation capacity, which could range from wind and solar to hydroelectricity projects.

For the main Yukon grid, the Government of Yukon will set a minimum regulatory requirement for the Yukon Energy Corporation to generate at least 93 per cent of electricity from renewable sources on average. It will then be up to the Yukon Energy Corporation to determine the best way to meet or exceed this target.

For off-grid communities, the Government of Yukon will continue to work in partnership with Yukon First Nations, communities and ATCO Electric Yukon to establish community-based renewable electricity projects in order to reduce diesel use for electricity generation by 30 per cent by 2030. Efforts to substitute some of the diesel that continues to be used for electricity generation with clean diesel alternatives like biodiesel and renewable diesel will help us reduce greenhouse gas emissions even further.

Investments in new renewable electricity generation will create local jobs and opportunities, but electricity rates may increase. This is in part because significant capital investments will be needed. It is also because the full costs of using and relying on diesel and other fossil fuels – like air pollution, greenhouse gas emissions and fuel spills – are not reflected in the fees we currently pay for these energy sources.

The Government of Yukon will strive to minimize the impact of any electricity rate increases on Yukoners by helping individuals, families and businesses use energy more efficiently. We will also work with Yukon's electrical utilities to facilitate energy-efficient practices and reduce demand at peak times. This will reduce the amount of new electricity generation infrastructure that needs to be built and the related impacts on electricity rates.

The Yukon Energy Corporation released a draft version of its 10-year renewable electricity plan, "Electricity for 2030," in January 2020. The plan identifies the electricity generation and storage projects that are needed to exceed the 93 per cent regulatory requirement that will be established under *Our Clean Future*. The Yukon Energy Corportion expects that its plan will result in 97 per cent renewable electricity on the main grid on average by 2030. For more information, visit yukonenergy.ca.



Dempster Highway. Photo: Fritz Mueller.

Transportation and heating

The issue

Two-thirds of the energy we use for transportation and heating comes from fossil fuels. Over the next 10 years, we need to reduce our reliance on fossil fuels in these areas.

Our targets

By 2030, we will meet 50 per cent of our heating needs with renewable energy sources. For transportation, we expect to see emissions from road transportation go down by at least 30 per cent by 2030, compared to 2010, to reach the overall greenhouse gas reduction target for Yukon.

How we will meet them

We will meet these targets through efficiency improvements to reduce energy demand, switching to clean electricity for some of our transportation and heating needs, developing local renewable heat sources like wood energy, and using cleaner transportation fuels.

Adapting to climate change

The issue

We are already experiencing significant changes to our climate. Since 1948, temperatures in northern Canada have increased by 2.3 degrees Celsius, with temperature rise being most rapid in Yukon and the Northwest Territories[6]. This is close to three times the rate at which global temperatures are rising. Over the same period, rain and snowfall increased by six per cent in Yukon and has become more unpredictable[7].

Some climate change impacts we have experienced, and will continue to experience, are:

- Permafrost thaw, which is damaging buildings and roads, changing landscapes and affecting ecosystems;
- Changes to weather and conditions on the land, which are reducing access to country foods, deepening food security concerns, and impacting health and cultural identities;
- More frequent extreme weather events, which can destroy habitats and homes and cause flooding;
- More severe forest fires, which pose a risk to communities and affect ecosystems and wildlife; and
- Glacier melt, which is affecting river flow patterns, water temperatures and aquatic health.

Adapting to climate change involves making informed, forward-looking decisions to minimize the negative impacts that climate change may have on our health, wellbeing, ways of life, and livelihoods while also taking advantage of new opportunities that may arise. In Yukon, effective adaptation will save lives, support healthy ecosystems, minimize damage to buildings and infrastructure, and protect Indigenous cultures and ways of life.

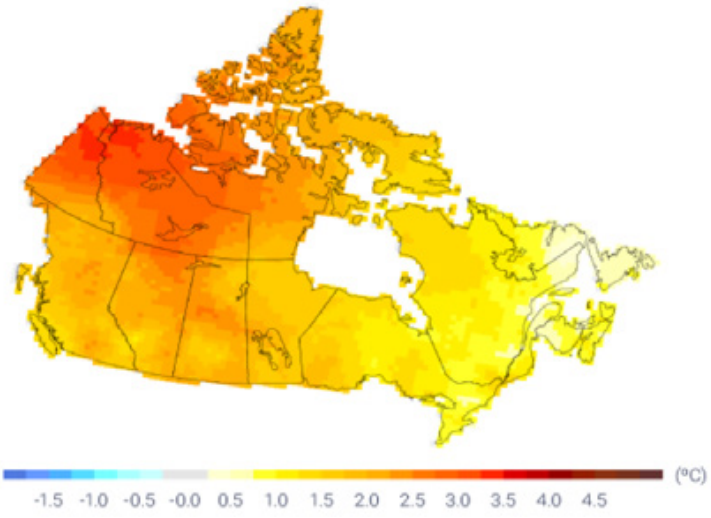


Figure 6. Change in annual temperature across Canada from 1948 to 2016. Figure from Canada's Changing Climate Report.

6 Government of Canada, 2019. Canada's Changing Climate Report.
7 Streicker, J., 2016. Yukon Climate Change Indicators and Key Findings 2015. Northern Climate ExChange, Yukon Research Centre.



Our target

By taking action to adapt to climate change, including impacts we are already experiencing and those yet to come, we will make sure that Yukon is highly resilient to the impacts of climate change by 2030.

To track progress toward this target, the Government of Yukon will work with Indigenous and municipal partners to assess how exposed Yukoners are to climate impacts, and how climate change will impact people and communities in different ways. We will also assess the ability of our built, natural and social systems to moderate potential damages, take advantage of opportunities, and cope with the consequences of climate change in the territory. Things we may track as part of this work could be the number of communities that have prepared climate change adaptation plans or the number of Yukoners that are living in high-risk areas.

Our work with Indigenous and municipal partners will also inform a common understanding of what it means to be climate resilient, as well as the ways in which communities are already resilent because of strong community connections, an intimate understanding of the land, or other sources of strength.

How we will meet it

We will increase Yukon's resiliency to climate change by taking action to reduce our exposure to climate hazards like wildfires and flooding, decrease how sensitive we are to those hazards, and increase our capacity to adapt. Our actions will be informed by Indigenous, local and scientific knowledge and ways of knowing, doing and being. Our efforts will touch on infrastructure, housing, land use planning, emergency preparedness, ecosystem health, food security, and health and wellbeing in recognition of how broadly climate change can affect our lives. We will work with partners across Yukon to share information, build capacity to understand and respond to climate change impacts, and plan for the future.

When planning for the climatic changes we expect to see, it is important to recognize that there is a range of possible climate impacts depending on global greenhouse gas emissions. In order to make sure we are planning conservatively, we will assume that global greenhouse gas emissions will continue along their current path when forecasting how Yukon's climate will change. Right now, global greenhouse gas emissions are most consistent with the Intergovernmental Panel on Climate Change's RCP8.5 pathway, which projects 2.6 to 4.8 degrees of warming globally by the end of the century. Even if we do not experience this level of warming, Yukoners will benefit from the investments in people and communities that climate change adaptation involves.

A risk-based and human-centered approach

Not all individuals, households or communities will be affected in the same way by the changes that are coming. Our ability to adjust to changing conditions, reduce potential damages and take advantage of new opportunities differs from person to person and community to community. For example, resilience



Carcross Commons opening.

to climate change is affected by the condition of our homes, whether we rent or own, our ability to afford insurance, the health conditions we live with, and the presence of friends, family and community to support us and provide comfort during difficult times. As a result, climate change can amplify socioeconomic stresses that individuals, households and communities are already facing.

In *Our Clean Future*, our approach to adaptation recognizes the importance of reducing the risks we all face while also working to alleviate the conditions that can make people more vulnerable to climate change. This includes working to improve human health, food security and housing to enhance the resilience of Yukoners and Yukon communities.



Fireweed Market.

Building a green economy

The issue

A green economy creates economic prosperity while protecting and restoring the natural environment in order to build a healthy, prosperous future for generations to come. In a green economy, energy and other resources are used efficiently, with minimal waste. Economic activities and operations release fewer carbon dioxide and other greenhouse gas emissions. A green economy is also resilient and inclusive so that communities, businesses and individuals can adapt to the impacts of climate change and take advantage of new opportunities.

There are many opportunities for Yukoners as we build a green economy in the territory alongside national and international efforts. As local, national and global demand for green goods and services increases, there are opportunities for Yukon innovators, entrepreneurs and businesses to supply clean energy and find ways to use energy more efficiently. The knowledge economy will grow as Yukoners come up with innovative solutions to local and global challenges. Efforts to use energy and other resources more efficiently will also reduce operating costs for Yukon businesses.

What we will do

Yukon's approach to a green economy focuses on:

- Helping Yukon businesses, individuals and communities plan for, and benefit from, the economic opportunities that will arise as we take action on climate change and energy;
- Supporting innovation and the knowledge economy and recognizing the achievements of local green businesses and organizations; and
- Making it easier for businesses, communities and entrepreneurs to access funding and support for green projects across Yukon.

Building a green economy will help Yukoners take care of the natural environment so it can support long-term jobs and economic activity, as well as continued traditional and cultural activities and strong mental and physical wellbeing. A green economy recognizes principles upheld by Indigenous people for millenia that people must respect and take care of the land so that the land can take care of us.

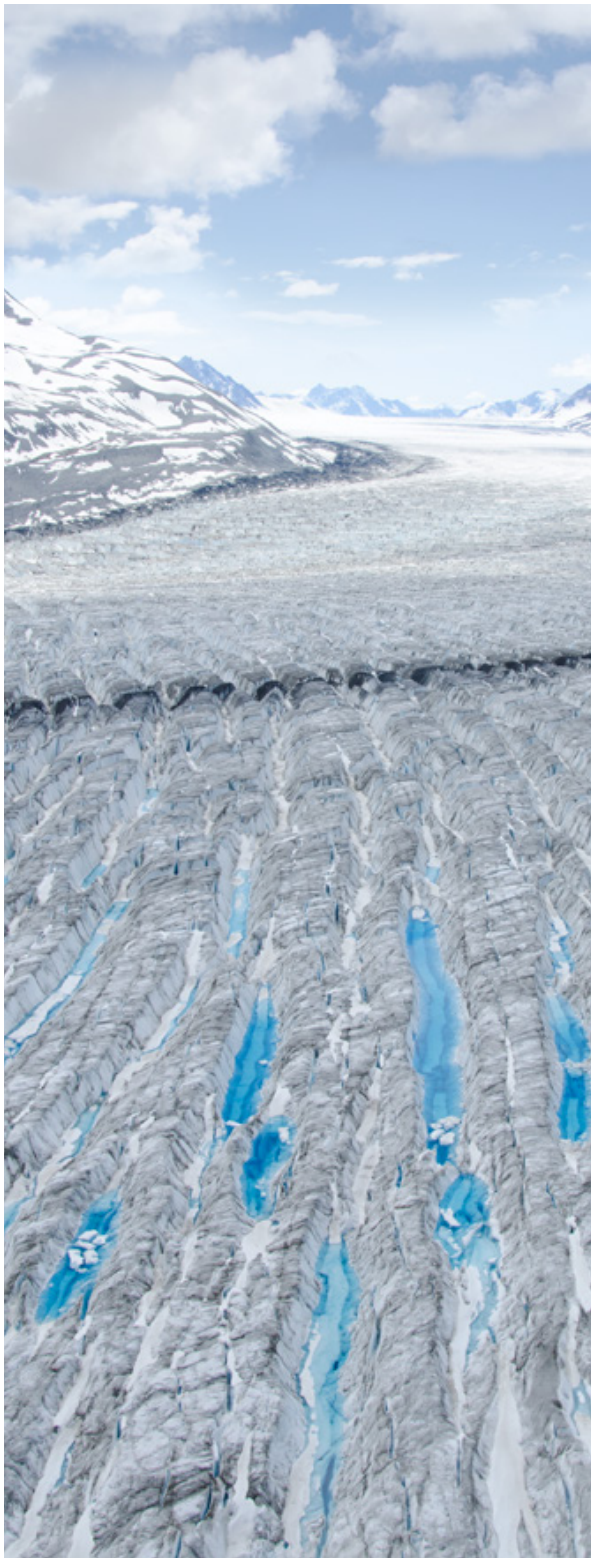
Tracking progress

We will track our progress toward building a green economy by looking at changes to greenhouse gas emissions per person and greenhouse gas emissions per unit of real gross domestic product over time. These indicators will tell us whether Yukon's economy is becoming more efficient in terms of the greenhouse gas emissions we generate relative to the number of people living in the territory and the size of our economy.

Carbon pricing

A price on carbon pollution is one way that the Government of Canada is stimulating the green economy. The Government of Canada's carbon levy encourages individuals and businesses to invest in low-carbon alternatives and fosters innovation.

The Government of Yukon's carbon rebate returns carbon pricing revenues from the Government of Canada to Yukon individuals, businesses, First Nations and municipalities. The Government of Yukon's carbon rebate upholds the principles of the Pan-Canadian Framework on Clean Growth and Climate Change while protecting vulnerable families, and ensuring the territory remains competitive as we transition to a green economy. For businesses, Yukon's carbon rebate includes a super green credit to encourage future investments in renewable energy generation and energy efficiency.



Kaskawulsh Glacier.

Taking action

Our Clean Future: is organized into seven areas:


Transportation


Homes and buildings


Energy production


People and the environment


Communities


Innovation


Leadership

Within each area, there are several objectives that we will work toward over the next 10 years that reflect the priorities of the Government of Yukon and participating municipal and Indigenous partners.

Each objective contributes to one or more of these four goals:



Reducing greenhouse gas emissions;


Ensuring Yukoners have access to reliable, affordable and renewable energy;


Adapting to the impacts of climate change; and


Building a green economy.

Actions

To reach each objective, we need to take specific, tangible actions. The Government of Yukon's actions in this strategy lead by example through major improvements to government vehicles and buildings while also supporting Indigenous governments and organizations, municipalities, businesses and individuals to take collaborative action to build a strong, healthy future.

The actions in *Our Clean Future* are the Government of Yukon's top priorities for addressing climate change, meeting energy needs and building a green economy over the next 10 years. For each action, the Government of Yukon department or agency responsible for leading the implementation of that action is listed for transparency and accountability. In many cases, other departments will be involved as well.

In addition to the Government of Yukon's actions, Indigenous and municipal partners have been invited to identify actions they will take to work toward our collective objectives set out in *Our Clean Future*. Several partner actions are included in this version of *Our Clean Future* and the door remains open for partners to identify additional actions in the future.

Timing

The Government of Yukon's actions will be updated every three to four years. This will ensure the strategy remains relevant from now until 2030 and that we remain up-to-date on best practices and new developments.

Funding

To implement many of the Government of Yukon's actions in this strategy, we will continue to depend on partnerships with the federal government. In particular, we hope to receive continued federal support for investments in clean transportation, building energy efficiency, renewable energy projects, emergency preparedness and response, and community adaptation.

In partnership with the federal government, the Government of Yukon plans to spend over $500 million over the next 10 years to implement *Our Clean Future*. This investment will put Yukon on the path to significantly reduce our greenhouse gas emissions from transportation, heating, electricity generation and other areas, prepare our communities for ongoing climate change, and enable all Yukoners to participate in these efforts by providing necessary financial and technical support.

Over $400 million of this investment will directly support economic development and recovery by investing in local renewable energy, infrastructure and building projects, encouraging purchases of green technologies like zero emission vehicles, and supporting Yukon businesses and workers to develop new skills for the green economy.

Government of Yukon departments and agencies

CS: Community Services
EcDev: Economic Development
EDU: Education
EMR: Energy, Mines and Resources
ENV: Environment
ECO: Executive Council Office
FIN: Finance
HSS: Health and Social Services
HPW: Highways and Public Works
JUS: Justice
PSC: Public Service Commission
TC: Tourism and Culture
YDC: Yukon Development Corporation
YEC: Yukon Energy Corporation
YHC: Yukon Housing Corporation



Tr'ondëk Hwëch'in Farm.

Working together

Community leadership and successful partnerships are key to addressing climate change. In Yukon, many impactful climate change and energy projects have been driven by community champions and supported by collaborative partnerships between governments, organizations, businesses and individuals. These projects range from the Old Crow solar project, Kluane wind project and solar panels in Mayo to the Tr'ondëk Hwëch'in First Nation and Carcross-Tagish First Nation community farms. Moving forward, Indigenous governments and organizations, municipalities, businesses, organizations, individuals, youth and Elders will all continue to play key roles building a clean future for Yukon.

Indigenous and municipal leadership

The objectives set out in each of the seven areas of *Our Clean Future* were identified as priorities for Yukon by the Government of Yukon and participating Yukon First Nations, transboundary Indigenous groups and Yukon municipalities. Several Indigenous and municipal partners have put forward ambitious actions they will take to work toward the objectives that are particularly relevant to their communities, complementing and building on the Government of Yukon's efforts in those areas and demonstrating continued community leadership.

In addition to the actions highlighted below, the Council of Yukon First Nations and the Assembly of First Nations-Yukon Region are leading the development of a Yukon First Nations climate change vision and action plan that will complement *Our Clean Future* by providing a First Nations-led perspective on climate action in Yukon.

Indigenous- and municipal-led actions by area

	Purchase an electric or hybrid vehicle and install an electric vehicle charging station in Mayo.	Village of Mayo
	Implement challenge-based campaigns to encourage behavioral shifts on walking and active transportation, as well as on topics such as vehicle use, energy use, and waste.	City of Dawson
	Develop a program and educational campaign for reducing winter idling.	City of Dawson
	Retrofit the Village of Mayo Community Centre to be more energy efficient based on an energy assessment completed for the facility.	Village of Mayo
	Explore opportunities to replace diesel heat in Old Crow with fast-growing, locally harvested willow distributed through a district heat system.	Vuntut Gwitchin Government
	Implement a water metering and bleeder reduction program.	City of Dawson
	Partner with the University of Saskatchewan to improve and develop more comprehensive energy audits in the Gwich'in communities.	Gwich'in Tribal Council
	Develop an energy action plan for the Inuvialuit Settlement Region by 2021.	Inuvialuit Regional Corporation.
	Build a 1.5 megawatt (MW) solar farm in Beaver Creek that will displace up to 60 per cent of the diesel used for electricity generation in the community.	White River First Nation
	Build a solar farm in Old Crow that will meet 24 per cent of Old Crow's electricity demand and enable the diesel generators to be turned off for 2,200 hours each year.	Vuntut Gwitchin Government
	Set up a wind measurement tower in summer 2020 to investigate the potential for a wind energy project to meet Old Crow's electricity demand in the winter months.	Vuntut Gwitchin Government
	Work with partner organizations to convert the Gwich'in Camp from full reliance on diesel power to hybridized renewable energy sources.	Gwich'in Tribal Council
	Continue to heat the Village of Mayo swimming pool using solar energy.	Village of Mayo
	Work with Polar Knowledge Canada to createand mobilize knowledge of sustainable energy, food sovereignty and revitalization and promotion of Indigenous Traditional Knowledge.	Gwich'in Tribal Council

Create municipal incentives for green buildings, businesses, and business practices.	City of Dawson
Develop a climate change strategy for the Inuvialuit Settlement Region by 2021.	Inuvialuit Regional Corporation
Conduct urban fire smarting.	Village of Haines Junction
Develop a Community Energy and Implementation Plan for Old Crow that will identify activities to reduce reliance on fossil fuels and achieve the 2019 Vuntut Gwitchin First Nation General Assembly resolution to reach carbon neutrality by 2030.	Vuntut Gwitchin Government
Create a reserve fund for projects related to climate change, energy, and green economy, and fund it from the municipal carbon tax rebate.	City of Dawson
Set improved service standards with respect to waste pickup, plowing, and bleeders.	City of Dawson
Explore and implement a comprehensive composting program to encourage and/or incentivize increased diversion of food waste.	City of Dawson
With support from Gender Equality Canada, work with women artisans in Beaufort Delta communities to address the systemic gaps that are hindering their business's opportunities.	Gwich'in Tribal Council
Continue looking for partnerships to build innovative technical solutions to decrease the diesel dependency in the Gwich'in Settlement Area.	Gwich'in Tribal Council
Create an Energy and Sustainability Analyst position by 2020 to help build the Council of Yukon First Nations' capacity to assist Yukon First Nations in the pursuit of projects, programs and policies that support renewable energy and reduce greenhouse gas emissions as well as provide guidance and visioning on the creation of a Yukon First Nations Climate Strategy and help strengthen Yukon First Nations energy literacy and capacity overall.	Council of Yukon First Nations
Develop a policy for municipal operations and events, including with respect to resource use, waste, and energy efficiency.	City of Dawson
Continue to run the Climate Future Exchange program to connect northern youth to their counterparts from other regions and enable them to create community-based projects that use Indigenous knowledge to reduce carbon footprint in the Gwich'in Settlement Area.	Gwich'in Tribal Council
Continue to host energy and climate change terminology workshops.	Inuvialuit Regional Corporation

Indigenous and municipal partners will continue to be able to put forward actions they will take to support a clean future through the online version of this strategy.

Individuals, businesses and organizations

Our Clean Future also creates many opportunities for individuals, businesses and organizations to take part in reducing emissions, enhancing energy security, making Yukon more resilient, and building a green economy through financial support, information and advice. Here are some of the ways you can participate and help ensure we are able to build the clean, resilient Yukon we want for the future.




Yukon in 2030
Here are some of the ways Yukon could look different in 2030 as a result of the objectives and actions in this strategy.
Our mining industry will produce fewer emissions of greenhouse gases per unit of production.
50 per cent of our heat will come from renewable energy.
Native species will be able to move across the landscape in response to climate change.
We will be better prepared to respond to emergencies.
Our homes and buildings will be substantially more energy efficient.
More people will use public and active transportation.
Up to 97 per cent of our electricity will be generated by hydro, wind, solar, biomass and other renewable sources.
We will grow more of our food locally.
Businesses will capitalize on opportunities for green innovation and entrepreneurship.
There will be 4,800 zero emission vehicles in Yukon.



Area #1: Transportation

Currently, almost all the energy we use to meet transportation needs comes from fossil fuels. As a result, transportation by road and air is the largest source of greenhouse gas emissions in Yukon, contributing 61 per cent of total emissions.[8] Close to 90 per cent of transportation emissions come from road transportation, with a relatively equal split between personal vehicles and commercial and industrial vehicles, including those that transport food, fuel and other products. The remaining transportation emissions are from aviation.

Our approach to transportation will make it easier for Yukoners to use clean forms of transportation, reducing fuel costs for individuals, families and businesses as well as greenhouse gas emissions. We will respond to the impacts of climate change on our transportation systems to ensure Yukon's economy remains strong and resilient. Our transportation objectives are supported by efforts in other areas of this strategy that will reduce our dependence on imported fossil fuels and other products by supporting local goods and services.

Transportation objectives at a glance

CO₂ $	Increase the number of zero emission vehicles on our roads.
CO₂	Reduce the lifecycle carbon intensity of transportation fuels.
CO₂ ⚡ $	Increase the use of public and active transportation.
CO₂ ⚡	Reduce the carbon footprint from medium and heavy-duty vehicles.
CO₂ ⚡ $	Be more efficient in how and when we travel.
$	Ensure roads, runways and other transportation infrastructure are resilient to the impacts of climate change.

8 Government of Yukon, 2020. Greenhouse gas emissions in Yukon.

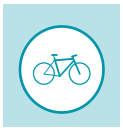
Increase the number of zero emission vehicles on our roads.

Increasing the use of electric vehicles and other vehicles with low or zero greenhouse gas emissions is one of the most significant ways we can reduce emissions. There are already several electric vehicles in Yukon, and they are a reliable and affordable transportation solution, even in our cold climate. Supporting a broader transition to zero emission vehicles will allow Yukoners to continue to go where and when they need to while reducing greenhouse gas emissions, improving air quality, and supporting local dealerships. While electric vehicles have been shown to have lower lifecycle greenhouse gas emissions than fossil fuel vehicles[9], Yukon will support efforts to address other social and environmental concerns with electric vehicle supply chains and to continue reducing the lifecycle emissions of electric vehicles.

Our target for 2030 is to have at least 4,800 zero emission vehicles registered in the territory – or approximately one in every eight passenger vehicles on the road. Our commitment to meet at least 93 per cent of Yukon's electricity needs from renewable sources, on average, while aiming for 97 per cent, will ensure these vehicles are powered sustainably.

ACTIONS

T1.	Work with local vehicle dealerships and manufacturers to establish a system by 2024 to ensure zero emission vehicles are 10 per cent of light duty vehicle sales by 2025 and 30 per cent by 2030.	EMR
T2.	Ensure at least 50 per cent of all new light-duty cars purchased by the Government of Yukon are zero emission vehicles each year from 2020 to 2030.	HPW
T3.	Provide a rebate to Yukon businesses and individuals who purchase eligible zero emission vehicles beginning in 2020.	EMR
T4.	Continue to install fast-charging stations across Yukon to make it possible to travel between all road-accessible Yukon communities by 2027 and work with neighbouring governments and organizations to explore options to connect Yukon with BC, NWT and Alaska.	EMR
T5.	Provide rebates to support the installation of smart electric vehicle charging stations at residential, commercial and institutional buildings in collaboration with Yukon's public utilities beginning in 2020.	EMR
T6.	Require new residential buildings to be built with the electrical infrastructure to support Level 2 electric vehicle charging beginning on April 1, 2021.	CS
T7.	Draft legislation by 2024 that will enable private businesses and Yukon's public utilities to sell electricity for the purpose of electric vehicle charging.	EMR
T8.	Continue to run public education events and campaigns to raise awareness of the benefits of electric vehicles and how they function in cold climates.	EMR



Reduce the lifecycle carbon intensity of transportation fuels.

Even with more zero emission vehicles on the roads and more people walking, cycling or taking the bus, liquid fossil fuels like gasoline and diesel are expected to be the main source of energy for transportation in Yukon over the next 10 years. As a result, a key way to reduce greenhouse gas emissions from transportation in the near term is to reduce the lifecycle carbon intensity – the greenhouse gas emissions per unit of energy provided – of the fuels we use. We can reduce the lifecycle carbon intensity of gasoline and diesel by blending them with ethanol, biodiesel or renewable diesel, which are renewable fuels produced from organic matter like agricultural waste and plant oils. Renewable fuels produce fewer greenhouse gas emissions than fossil fuels, even when taking a lifecycle approach that accounts for the emissions associated with land clearing and other agricultural practices that may be needed to produce the fuels.[10,11] Renewable fuels also protect local air quality because they produce fewer harmful tailpipe emissions than gasoline and diesel.

ACTIONS

T9.	Require all diesel fuel sold in Yukon for transportation to align with the percentage of biodiesel and renewable diesel by volume in leading Canadian jurisdictions beginning in 2025, aiming for around 20 per cent.	ENV
T10.	Require all gasoline sold in Yukon for transportation to align with the percentage of ethanol by volume in leading Canadian jurisdictions beginning in 2025, aiming for around 10 per cent.	ENV

Increase the use of public and active transportation.

Increasing the number of people who walk, bike and use public transit is another key way to lower greenhouse gas emissions. By reducing the number of people driving vehicles, investments in public and active transportation also reduce congestion, improve air quality and help people lead active, healthy lives. Making it easier to get around without a vehicle can also contribute to more inclusive communities by providing an accessible and affordable way to get from one place to another. While transportation options in and around Whitehorse are key to reducing greenhouse gas emissions, we will also look for public and active transportation solutions in and between Yukon's smaller communities.

Our target is for the percentage of commuting trips in Whitehorse made by drivers in single occupant vehicles to decrease to 55 per cent of all trips by 2031, as set out in the City of Whitehorse's Transportation Demand Management Plan.

10 Natural Resources Canada, 2020. "Biodiesel." https://www.nrcan.gc.ca/energy/efficiency/energy-efficiency-transportation-and-alternative-fuels/alternative-fuels/biofuels/21609

11 Natural Resources Canada, 2020. "Ethanol." https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-transportation/alternative-fuels/biofuels/ethanol/3493



ACTIONS

T11.	Provide rebates to encourage the purchase of electric bicycles for personal and business commuting beginning in 2020.	EMR
T12.	Continue to support municipalities and First Nations to make investments in public and active transportation infrastructure.	CS
T13.	Continue to incorporate active transportation in the design of highways and other Government of Yukon transportation infrastructure near communities.	HPW

Reduce the carbon footprint from medium and heavy-duty vehicles.

Yukoners rely heavily on goods brought up from southern Canada and around the world. While we are making progress toward meeting more of our needs locally, shipping of food, fuel, and other products will continue to be an important part of our lives and economy, given Yukon's relative remoteness. We also rely on medium duty vehicles like school buses, road clearing equipment and mail delivery vans to keep communities safe and accessible and to meet our daily needs. We will work to find efficiencies and reduce emissions from medium and heavy-duty vehicles.

ACTIONS

T14.	Update the Government of Yukon's heavy-duty vehicle fleet by 2030 to reduce greenhouse gas emissions and fuel costs.	HPW
T15.	Begin a pilot project in 2021 to test the use of short-haul medium and heavy-duty electric vehicles for commercial and institutional applications within Yukon.	EMR
T16.	Train the Government of Yukon's heavy equipment operators on efficient driving techniques for all new equipment by 2022.	HPW

Be more efficient in how and when we travel.

The COVID-19 pandemic has proven that we can be much more efficient in how and when we travel. It is possible for a significant number of people to work from home, reducing congestion and air pollution while continuing to deliver results. Large meetings and conferences can successfully be held through videoconferencing technology, rather than flying thousands of kilometres for a few hours of interaction. As we emerge from the COVID-19 pandemic, we will continue to invest in technology that allows us to move ideas rather than people and to pursue long-term changes to how we work and travel. Recognizing that face-to-face interactions are important, when we do travel, we will make sure we do so efficiently such as by using efficient vehicles and carpooling with colleagues or friends. These efforts will help Yukoners save money while also reducing greenhouse gas emissions, cutting back on congestion, reducing our dependence on fossil fuels, making roads safer and reducing air pollution.

Safer and more efficient driving behaviours like slower acceleration, more measured braking and driving the speed limit can increase the fuel efficiency of your vehicle by up to 25 per cent.
Source: Government of Canada, 2020. "Fuel Efficient Driving Techniques."

ACTIONS

T17.	Expand the Government of Yukon's video and teleconferencing systems and require employees to consider these options when requesting permission for work travel by 2022.	HPW
T18.	Implement new policies to enable Government of Yukon employees in suitable positions to work from home for the longer term by 2022.	PSC
T19.	Develop a planning and engagement strategy by 2022 to change how and where Government of Yukon employees work by providing choices and flexibility through a modern workplace.	HPW
T20.	Develop and implement a system by 2021 to coordinate carpooling for Government of Yukon staff travelling by vehicle for work within Yukon.	HPW
T21.	Develop guidelines for the Government of Yukon Fleet Vehicle Agency's fleet by 2021 to ensure appropriate vehicles are used for the task at hand.	HPW
T22.	Incorporate fuel efficiency into purchasing decisions for Government of Yukon fleet vehicles beginning in 2020 to reduce greenhouse gas emissions and fuel costs.	HPW
T23.	Expand virtual health care services to Whitehorse medical clinics by 2022 in order to improve access to healthcare while reducing greenhouse gas emissions from travel to and from Whitehorse.	HSS
T24.	Continue to operate the Yukon Rideshare program to make carpooling and other shared travel easier.	ENV

Ensure roads, runways and other transportation infrastructure are resilient to the impacts of climate change.

Climate change is already affecting Yukon's transportation infrastructure. Thawing permafrost damages our roads, runways and bridges and increases maintenance costs. Landslides, flooding, forest fires and other natural hazards can wash out roads, cutting communities off from critical supply routes. It is important that we address the impacts of climate change on our transportation infrastructure to ensure we stay safe and connected and to protect our economy and livelihoods.

ACTIONS

T25.	Complete a climate change vulnerability study of the road transportation network by 2023 to inform the development of standards and specifications.	HPW
T26.	Establish a geohazard mapping program for major transportation corridors and prioritize sections for targeted permafrost study by 2022.	EMR
T27.	Analyze flood risk along critical transportation corridors at risk of flooding by 2023.	ENV
T28.	Continue to conduct climate risk assessments of all major transportation infrastructure projects above $10 million[12], such as through the federal Climate Lens assessment.	HPW



Alaska Highway.

12 $10 million dollars is the threshold established by the Government of Canada for climate risk assessments through the Climate Lens.



Area #2: Homes and buildings

Many Yukoners spend a lot of time inside, whether at home, at work or at school. How we design, use and heat these buildings affects our comfort, safety, productivity, health and finances.

Right now, many buildings use more energy than they need to and heating buildings accounts for 21 per cent of Yukon's greenhouse gas emissions. Taking steps to use less energy saves money, stimulates the economy and supports green jobs in construction. Improving energy efficiency is a key step toward significant greenhouse gas reductions through heating highly efficient buildings with low-carbon energy sources like wood and clean electricity.

The Government of Yukon will lead by example in this area by undertaking energy efficiency retrofits and installing renewable heating systems to reduce greenhouse gas emissions from Government of Yukon buildings by 30 per cent by 2030, compared to 2010.

At the same time as we make our buildings more efficient, we can ensure they are designed to be more resilient to fires, floods, permafrost thaw and heat stress. This will reduce long-term repair and maintenance costs, health risks like mould, and improve public safety.

Homes and buildings objectives at a glance

	Improve the energy efficiency and climate resilience of existing homes and buildings.
	Ensure **new** homes and buildings are built to be low-carbon and climate-resilient.
	Increase the use of biomass and other renewable energy sources for heating.
	Use energy more efficiently and better align energy supply and demand.

The Government of Yukon will invest $30 million dollars on average each year in energy retrofits for homes and buildings. This will include financial support for individuals and businesses, support for First Nations and municipal governments, and retrofits to Government of Yukon buildings.

Improve the energy efficiency and climate resilience of existing homes and buildings.

Many existing homes and buildings can be improved to use less energy and to be more resilient to the impacts of climate change. The energy efficiency of our homes and buildings is affected by insulation, draftiness, and the mechanical and electrical systems we use for heat and power. Similarly, how many trees surround our buildings affects our vulnerability to forest fires while our foundation and roof affect our resilience to flooding and permafrost thaw. Taking action to improve existing homes and buildings will lead to many benefits for Yukoners, from saving money on heating and electricity to improving comfort and safety. It is important that our efforts in this area are accessible to all Yukoners, including tenants and home and building owners.

Our target is to complete 2,000 residential, commercial and institutional energy efficiency retrofits by 2030.

The amount of money paid by insurance companies in Canada for property damage due to severe weather has increased from $400 million per year in the 1980s to over one billion dollars per year. This is contributing to substantial increases in premiums for home and property insurance across Canada.
Source: Globe and Mail, 2018. "The costs of climate change are rising."



Home with solar panels.



ACTIONS

H1.	Conduct retrofits to Government of Yukon buildings to reduce energy use and contribute to a 30 per cent reduction in greenhouse gas emissions by 2030.	HPW
H2.	Conduct energy assessments of Government of Yukon buildings to identify opportunities for energy efficiency and greenhouse gas reductions, with the first period of assessments completed by 2025 and the second period completed by 2030.	HPW
H3.	Provide low-interest financing to support energy efficiency retrofits to homes and buildings beginning in 2021.	EMR & CS
H4.	Continue to provide financial support to assist First Nations and municipalities to complete major energy retrofits to institutional buildings across Yukon, aiming for 30 retrofits by 2030.	EMR
H5.	Continue to provide financial support for municipal and First Nations energy efficiency projects.	CS
H6.	Continue to work with Yukon First Nations to retrofit First Nations housing to be more energy efficient.	YHC
H7.	Continue to retrofit Government of Yukon community housing to reduce greenhouse gas emissions in each building by 30 per cent.	YHC
H8.	Continue to provide rebates for thermal enclosure upgrades and energy efficient equipment to reduce energy use in homes and commercial buildings.	EMR
H9.	Assess ways to ensure Yukoners can access adequate insurance for fires, floods and permafrost thaw by 2023.	CS
H10.	Develop and implement a plan by 2024 to conduct routine monitoring of the structural condition of Government of Yukon buildings located on permafrost.	HPW
H11.	Assess options to provide financial support for actions to improve the climate resiliency of homes and buildings by 2023.	ENV

Ensure new homes and buildings are built to be low-carbon and climate-resilient.

It is also important that new buildings are built to be low-carbon and climate-resilient from the beginning. Making sure new homes and buildings are built to energy efficient standards and with the potential impacts of climate change in mind will save money for homeowners and building owners over the long run, decrease pressure on the electrical grid, reduce greenhouse gas emissions and improve safety and comfort.

Across Canada, governments are working together toward net-zero energy ready buildings. This means buildings will be designed to be so energy efficient they could be heated and powered with just the energy from onsite renewables. In general, this means that new buildings in Canada will be designed to be 50 to 70 per cent more energy efficient than currently required by the 2015 National Building Code. The Government of Yukon will work with the Government of Canada to ensure new codes are suitable to northern Canada. Close to two-thirds of new homes in Whitehorse are already being built near this standard thanks to rebates from the Energy Solutions Centre.

ACTIONS

H12.	Work with the Government of Canada to develop and implement building codes suitable to northern Canada that will aspire to see all new residential and commercial buildings be net zero energy ready by 2032.	CS
H13.	Continue to require all new Government of Yukon buildings to be designed to use 35 per cent less energy than the targets in the National Energy Code for Buildings, in accordance with the Government of Yukon's Design Requirements and Building Standards Manual.	HPW
H14.	Adopt and enforce relevant building standards by 2030 that will require new buildings to be constructed to be more resilient to climate change impacts like permafrost thaw, flooding and forest fires.	CS
H15.	Continue to conduct climate risk assessments of all major building projects over $10 million that are built or funded by the Government of Yukon.	CS & HPW
H16.	Continue to provide rebates for new homes that are net zero energy ready, aiming for 500 homes by 2030.	EMR

Increase the use of biomass and other renewable energy sources for heating.

Increasing how much of our heating needs are met through local renewable sources will reduce greenhouse gas emissions and support the local economy. In the near term, our renewable heat options are electricity produced from renewable sources as well as wood and other forms of biomass energy. In the longer term, other forms of renewable heat like geothermal energy may also help meet our heating needs. When it comes to electric heating, we will focus on efficient, smart electric heating technologies like air source heat pumps with utility-controlled electric thermal storage that use less electricity than electric baseboards and have a significantly lower impact on peak electricity demand. For wood heating, we will focus on large commercial and government buildings with significant heating demand that will use large, efficient biomass systems with fewer air emissions. Local, sustainably harvested biomass to meet this heating demand is a low-carbon and renewable energy source that will support jobs in Yukon's wood products industry and help to reduce the risk of forest fires around Yukon communities.

Our targets are to replace 1,300 residential fossil fuel heating systems with smart electric heating systems and to support businesses, organizations and local governments to install 20 commercial and institutional biomass heating systems by 2030.

Biomass energy use can be a win-win for greenhouse gas reduction and climate change adaptation. The Government of Yukon has made it easier for Yukoners to use wood from Firesmarting and other forest fuel risk reduction efforts to heat homes and buildings. In particular, changes to the permits issued under the Forest Resources Act now allow private companies to collect wood from land clearing projects.

ACTIONS

H17.	Install renewable heat sources such as biomass energy in Government of Yukon buildings by 2030 to create long-term demand for renewable heating and contribute to a 30 per cent reduction in greenhouse gas emissions.	HPW
H18.	Provide low-interest financing to install smart electric heating devices in residential, commercial and institutional buildings in collaboration with Yukon's public utilities beginning in 2021.	EMR & CS
H19.	Provide low-interest financing to install biomass heating systems in commercial and institutional buildings beginning in 2021.	EMR & CS
H20.	Continue to assist First Nations to complete feasibility studies for the installation and operation of biomass heating systems.	EMR
H21.	Continue to provide rebates for residential, commercial and institutional biomass heating systems and smart electric heating devices and increase the current rebate for smart electric heating devices beginning in 2020.	EMR

H22.	Work with local industry to install and test 25 electric heat pumps with backup fossil fuel heating systems or utility-controlled electric thermal storage from 2020 to 2023.	EMR
H23.	Identify regulatory improvements that could support the growth of Yukon's biomass energy industry during the review of the *Forest Resources Act* by 2022.	EMR
H24.	Amend the *Air Emissions Regulations* by 2025 in order to regulate air emissions from commercial and institutional biomass burning systems to minimize the release of harmful air pollutants.	ENV
H25.	Analyze and compare the climate benefits of different types of biomass harvesting and use in Yukon by 2021 in order to identify recommended forest management practices to guide sustainable and low-carbon biomass use.	ENV

Use energy more efficiently and better align energy supply and demand.

Energy use is affected by how much we heat our buildings, whether we leave the lights on when we leave the house, what appliances we buy, and other behaviours. Using energy more efficiently will help Yukoners save money and reduce greenhouse gas emissions. It is also important to align the timing of when people use energy with when energy is available to us through demand-side management. For example, we can shift energy use away from peak times to other times when fewer people are using energy.

Demand-side management (DSM) includes a variety of tools to adjust demand for electricity. DSM initiatives can reduce the amount of electricity that people use at peak times or shift energy use away from peak times. DSM tools include financial incentives like time-of-use rates, utility control of household and business energy use, and education to change behaviour.

ACTIONS

H26.	Provide direction to the Yukon Utilities Board in 2020 to allow Yukon's public utilities to partner with the Government of Yukon to pursue cost-effective demand-side management measures.	YDC
H27.	Establish a partnership between the Government of Yukon, Yukon Energy Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs.	EMR & YEC
H28.	Complete the Peak Smart pilot project by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours.	YEC
H29.	Implement an education campaign for Government of Yukon building occupants and visitors by 2026 to encourage more energy efficient behaviours.	HPW

Area #3: Energy production

While over 90 per cent of the electricity we generate in Yukon comes from renewable sources, only 26 per cent of the heat energy we use is from renewable sources, with the rest coming from non-renewable sources like diesel and propane. Overall, about 24 per cent of the energy we use in Yukon comes from renewable resources. [13]

Our approach to energy production will see more renewable energy produced for both heating and electricity, combined with upgrades to the electricity grid and energy storage to make the best use of seasonal resources. This will allow us to continue to heat and power our lives with clean energy even as electricity demand grows and as we use more electricity for transportation and heating. Our efforts to produce more energy from renewable sources will work hand-in-hand with efforts to make our homes and buildings more energy efficient in order to decrease our dependance on fossil fuels and minimize the amount of electricity we generate from diesel and natural gas. At the same time, we will make sure our electricity generation, distribution and transmission infrastructure is climate-resilient so Yukoners continue to have access to safe and reliable power.

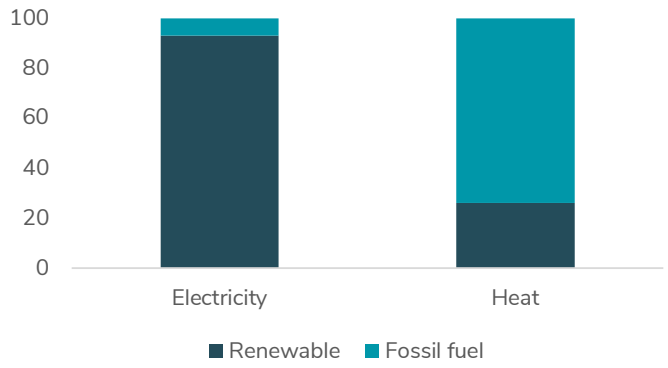


Figure 7. The percentage of electricity and heat energy that is produced by renewable sources and fossil fuels (2016).

Energy production objectives at a glance

CO_2 ⚡ $	Increase the supply of electricity generated from renewable sources.
CO_2 ⚡ $	Support local and community-based renewable energy projects for heating and electricity.
🏭 $	Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

13 Government of Yukon, 2018. Yukon's Energy Context.

Increase the supply of electricity generated from renewable sources.

It is important to increase the amount of electricity we produce from renewable sources as electricity demand grows and as we increasingly use electricity for transportation and heating needs. While most of our electricity currently comes from hydro, we also have other renewable energy sources available like wind, wood, solar and geothermal. Producing more of our electricity with local renewable energy will make us more self-sufficient and less vulnerable to changing fuel prices. Making sure we continue to supply most of our electricity through renewable sources is key to reducing our greenhouse gas emissions.

Through the Government of Yukon's Independent Power Production Policy and Micro-generation Program, Yukon communities and households can generate clean electricity and sell power to the grid. Participating households in the Micro-generation Program have earned close to $700 per year on average by selling excess electricity to the grid.

ACTIONS

E1.	While aiming for an aspirational target of 97 per cent by 2030, develop legislation by 2023 that will require at least 93 per cent of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	EMR & YDC
E2.	Require some of the diesel used to generate electricity on the Yukon Integrated System and in off-grid communities to be substituted with clean diesel alternatives like biodiesel and renewable diesel beginning in 2025, aiming for around 20 per cent.	EMR
E3.	Update the *Public Utilities Act* by 2025 to ensure an effective and efficient process for regulating electricity in Yukon.	JUS & EMR
E4.	Install renewable electricity generation systems in 5 Government of Yukon buildings in off-grid locations by 2025 to reduce reliance on diesel-generated electricity.	HPW
E5.	Evaluate the potential to generate renewable electricity at remote historic sites co-managed by the Government of Yukon and Yukon First Nations by 2022.	TC

Support local and community-based renewable energy projects.

Local and community-based renewable energy projects create jobs and opportunities across Yukon, support self-sufficiency and help Yukoners be part of the clean energy economy. Through this strategy, we will support communities and individuals to produce local renewable energy for heating and electricity, while creating opportunities for local businesses and contractors. We will also stay up-to-date on new and emerging energy technologies that may be able to meet Yukon's needs in the future, such as nuclear energy, and increase our knowledge of renewable and low-carbon energy sources that may be available in Yukon.

Our target is to have an operating independent power production project in all off-grid communities by 2030 in order to reduce diesel use for electricity generation by 30 per cent by 2030.

ACTIONS

E6.	Continue to provide financial and technical support for Yukon First Nations, municipalities and community organizations to undertake community-led renewable energy projects.	YDC
E7.	Work with Yukon's public utilities to continue to implement the Independent Power Production Policy that enables independent power producers, including Yukon First Nations and communities, to generate and sell electricity to the grid.	EMR
E8.	Increase the limit of the Standing Offer Program under the Independent Power Production Policy from 20 gigawatt hours (GWh) to 40 GWh by 2021 to support additional community-based renewable energy projects on Yukon's main electrical grid.	EMR
E9.	Develop a framework by 2022 for First Nations to economically participate in renewable electricity projects developed by Yukon's public utilities.	YDC
E10.	Continue to deliver the Micro-generation Program in collaboration with Yukon's public utilities, targeting 7 megawatts (MW) of installed renewable electricity capacity by 2030.	EMR
E11.	Develop legislation by 2023 to regulate geothermal energy development in Yukon.	EMR
E12.	Research the potential to use geothermal energy for heating and electricity, with a focus along Yukon fault systems, by 2025.	EMR



Transformer station.

Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

The impacts of climate change and extreme weather events can negatively affect electricity infrastructure like power lines. Climate change is also affecting rain, snowfall and glacier melt in Yukon, which in turn can impact our hydro-based electricity system. The Government of Yukon, through the Yukon Energy Corporation, is responsible for the safe and effective management of our electrical systems. Proactive climate change risk management is an operating imperative. This involves conducting research, forecasting future conditions, identifying risks and opportunities, developing adaptation options, and incorporating climate change into long-term planning and decision making.

ACTIONS

E13. Improve modelling of the impacts of climate change on hydroelectricity reservoirs by 2021 and incorporate this information into short, medium and long-term forecasts for renewable hydroelectricity generation.	YEC
E14. Develop a climate change adaptation plan for the Yukon Energy Corporation by 2022 that will identify risks and appropriate responses to ensure Yukon's main electrical grid is resilient to the impacts of climate change.	YEC
E15. Implement a glacier monitoring program in 2020 to improve our ability to predict the impacts of glacier melt on hydrological systems and hydroelectricity generation.	EMR

Area #4: People and the environment

Yukoners have a strong connection to the land.

We value and depend on our natural spaces, wild animals, and clean air and water. For Indigenous people in particular, a long history of taking care of the land has shaped and continues to shape Indigenous cultures, identities and worldviews. The connection that Indigenous people have with the land, water, and animals is also a source of strength, understanding, and resilience.

Because of the intimate relationship between people and the environment, particularly the relationships nurtured by Indigenous people over generations, climate change has significant ripple effects on ways of life, cultural identities and physical and mental health. Furthermore, the impacts of climate change interact with other pressures on ecosystems like land development, resource extraction and forest fires, resulting in cumulative effects on people and the environment. These effects can diminish other important services that healthy ecosystems provide for us like clean air and pure water.

As the climate continues to change, it is important to improve our understanding of how the natural environment is responding, using a combination of Indigenous, local and scientific knowledge and ways of knowing, doing and being. Prepared with this information, we will take action to protect the ecosystems, wild species and their habitats that are so important to Yukoners. We will strive to maintain and strengthen cultural practices, recognizing that our ways of life are often interconnected with the land. We will also protect and enhance the health and wellbeing of Yukoners, which are dependent on the health of the natural environment.

People and the environment objectives at a glance

	Respond to the impacts of climate change on wild species and their habitats.
	Maintain our ability to practice traditional and cultural activities on the land.
	Protect and enhance human health and wellbeing in a changing climate.

Respond to the impacts of climate change on wild species and their habitats.

Climate change is putting pressure on ecosystems, wild species and their habitats. Species ranges are projected to shift, snowpacks may become deeper, and streams are anticipated to change in flow, temperature and sediment levels. Extreme weather events, changes to the availability of prey and forage, and conditions favourable to new and invasive species will negatively affect native species and existing ecosystems, adding to the cumulative stress they are experiencing. In response, wild species may migrate to a new location, adapt, persist or decline. Ecosystems will be reconfigured with new assemblages of plants and animals, resulting in different and unpredictable ecological processes. Some ecosystems, such as wetlands, will be more susceptible than others. It is important that we better understand how climate change is affecting the natural environment and take action to minimize the impacts on ecosystems, wild species and their habitats, and the people that depend on them.

ACTIONS

P1.	Establish a standardized method to determine the health status of wetland ecosystems and complete a pilot study to measure the baseline conditions of various reference wetlands by 2022 to better understand future changes.	ENV
P2.	Adapt existing surface and groundwater monitoring networks by 2026 to be able to track long-term trends in water quality and quantity in a changing climate.	ENV
P3.	Continue to lead and participate in projects that improve our understanding of how climate change is affecting ecosystems, wild species and their habitats.	ENV & EMR
P4.	Continue to monitor key species that will provide an indication of the impacts of climate change on Yukon ecosystems and expand monitoring to more taxonomic groups.	ENV
P5.	Continue to incorporate climate change into the design of protected and managed areas using landscape conservation science in order to allow native species to move, adapt and survive in the face of climate change.	ENV
P6.	Continue to track new and invasive species to Yukon that could impact ecosystems and biodiversity.	ENV



People searching for species during BioBlitz in Tombstone Territorial Park.

Maintain our ability to practice traditional and cultural activities on the land.

Many people go out on the land to hunt, fish, harvest, travel from one community to another, and pursue other traditional and cultural activities. These activities are a critical part of culture and identity, particularly for Indigenous people. However, climate change is threatening the safety of these activities as weather, ice and trail conditions become increasingly unpredictable, even for highly experienced people in our communities. Climate change is also affecting when and where animals, fish and berries can be harvested, and may negatively impact the health or abundance of the species upon which people have traditionally relied. As the climate continues to change, cultural and historic sites that reflect past relationships with the land may be uncovered or threatened. We will work to maintain the ability to practice traditional and cultural activities on the land in order to sustain Yukon's rich and vibrant cultures and identities.

ACTIONS

P7.	Work with Yukon First Nations to develop a tailored hunter education program by 2023 that can be adapted and delivered by Yukon First Nations for First Nations citizens.	ENV
P8.	Work collaboratively with First Nations and the Inuvialuit to document information from historic sites and culturally important places on the North Slope that are at risk due to climate change by 2024.	TC



Cow moose with two calves.

Protect and enhance human health and wellbeing in a changing climate.

Climate change can negatively affect physical and mental health in many ways. Increased smoke from wildfires, new diseases, contaminants released from thawing permafrost, warmer temperatures and challenges harvesting traditional foods can all lead to respiratory, nutritional and other health concerns. At the same time, changes to the natural environment and to land-based cultural practices and livelihoods can cause anxiety and distress as we see our home changing before our eyes. It is important that we understand how climate change is impacting our health and take action to minimize these impacts. Beyond minimizing impacts, we should also strive to enhance our health and wellbeing so that we are more resilient to the changes that are coming.

ACTIONS

P9.	Provide training to healthcare providers beginning in 2023 to be better able to identify and treat the physical and mental health impacts of climate change.	HSS
P10.	Incorporate climate-related illnesses like heat stroke, respiratory illness, and vector-borne diseases into the new *1Health Yukon* health information system by 2023 to enable tracking of climate-related illnesses in Yukon.	HSS
P11.	Expand monitoring of concentrations of particulate matter in the air from biomass burning and forest fires to all Yukon communities by 2023.	ENV
P12.	Purchase a moveable clean air shelter by 2021 that can be set up in communities to protect public health during wildfire smoke events.	HSS
P13.	Provide financial support to vulnerable Yukoners to install cleaner air spaces in their homes and buildings beginning in 2023 to provide protection from wildfire smoke.	YHC
P14.	Analyze existing information on food insecurity in Yukon by 2023 to inform the development of a system to gather food insecurity data into the future.	HSS & EMR

Area #5: Communities



Dawson City.

Yukon is home to many unique, vibrant communities where we live, work, play and celebrate our cultures.

This strategy takes proactive steps to ensure our communities will be strong and resilient into the future. Our communities will increasingly be places where people walk, cycle and use public transportation to get around and where local businesses thrive. Our communities will be more resilient to the impacts of climate change and increasingly self-sufficient when it comes to food production.

Communities objectives at a glance

CO₂ ⚡	Design our communities to be low-carbon and resilient to the impacts of climate change.
	Ensure we are prepared for emergencies that are becoming more likely due to climate change.
CO₂	Supply more of what we eat through sustainable local food production.

Design our communities to be low-carbon and resilient to the impacts of climate change.

The ways our communities are designed affects how easy it is to walk to work, take public transit, or use renewable energy sources for heating and electricity. The design of communities and the underlying infrastructure also affects our ability to provide critical services like healthcare, clean and safe drinking water and waste management. Moving forward, we will focus on making communities more compact and efficient rather than expanding outwards, and make sure our homes are close to the places where we work and play. We will ensure that our communities are designed in ways that reduce our vulnerability to forest fires, permafrost thaw, flooding, drought and other natural hazards that are expected to worsen with climate change.

Building infrastructure to be climate-resilient adds about three per cent to the upfront cost. However, this investment pays back at about four times the amount invested due to lower repair costs and a longer useable lifespan. Engineers and planners can follow the Government of Canada's Climate Lens guideline to help them design resilient infrastructure.

Source: Global Comission on Adaptation, 2019. Adapt Now: A Global Call for Leadership on Climate Resilience.

ACTIONS

C1.	Expand geohazard map coverage to all Yukon communities with a high risk of permafrost thaw by 2025.	EMR
C2.	Develop flood probability maps for all Yukon communities at risk of flooding by 2023 that incorporate climate change projections.	ENV
C3.	Develop detailed guidelines by 2025 that can be used by the Government of Yukon and partners to develop walkable, bike-friendly and transit-oriented communities.	ENV
C4.	Continue to develop, encourage and apply applicable climate resiliency standards to community design and infrastructure development projects built by or receiving capital funding from the Government of Yukon.	CS
C5.	Continue to conduct detailed climate change risk assessments of all major community infrastructure projects over $10 million that are built or funded by the Government of Yukon.	CS
C6.	Continue to make recommendations to consider the impacts of climate change in regional land use and local area planning processes, which inform the Government of Yukon's development permitting and zoning decisions.	EMR
C7.	Continue to provide technical and administrative support to Yukon First Nations and municipalities to prepare integrated asset management plans.	EMR

Ensure we are prepared for emergencies that are becoming more likely due to climate change.

Climate change is increasing the likelihood of emergencies like severe forest fires and floods. Taking action to reduce the risk of these events, and ensuring we are prepared if they do happen, is critical. Through this strategy, we will work to build climate-resilient communities across Yukon and to have systems in place to effectively predict and respond to fires, floods and other emergencies like water shortages or landslides that may threaten Yukon communities.

Emergency preparedness is a good investment. As one example, for every dollar invested in effective early warning systems for floods, fires or heatwaves, taxpayers save ten dollars on average in avoided damages.
Source: Global Comission on Adaptation, 2019. Adapt Now: A Global Call for Leadership on Climate Resilience.

ACTIONS

C8.	Expand monitoring networks and improve modelling tools to generate reliable daily flood forecasts and relevant warnings for all at-risk Yukon communities by 2024.	ENV
C9.	Work with First Nations and municipalities to develop Wildfire Protection Plans for all Yukon communities by 2026 and to complete the forest fuel management activities outlined in the plans by 2030.	CS
C10.	Increase the capacity in Yukon Wildland Fire to prevent wildfires and respond to extended fire seasons by investing in staffing in 2020.	CS
C11.	Complete hazard identification and risk assessments (HIRAs) for all Yukon communities by 2022 that include climate change risks.	CS
C12.	Work with First Nations and municipalities to complete emergency management plans for all Yukon communities by 2022 informed by community hazard identification and risk assessments (HIRAs).	CS
C13.	Develop a territorial disaster financial assistance policy by 2022 to support recovery from natural disasters that result in extensive property damage or disruption to the delivery of essential goods and services.	CS

Supply more of what we eat through sustainable local food production.

Harvesting and producing more of the food we eat locally increases food security, contributes to the economy, and reduces how much food we need to ship into the territory. Local food production can include community greenhouses and gardens, backyard gardens, larger-scale agriculture and farming and small-scale animal husbandry. All these forms of local food production have an important role to play in a resilient, sustainable future that takes advantage of longer growing seasons and warmer temperatures as our climate changes.

The 2016-2021 Local Food Strategy for Yukon supports a more developed and sustainable local food system in the territory. Our Clean Future highlights the Government of Yukon's continued commitment to many relevant initiatives in the Local Food Strategy, including community food production.

ACTIONS

C14.	Incorporate support, where possible, for local food producers into Government of Yukon procurement processes beginning in 2020.	HPW
C15.	Continue to provide funding for community gardens and greenhouses, especially in rural communities.	EMR
C16.	Continue to provide technical advice to assist First Nations and municipal governments with their agricultural and animal husbandry projects.	EMR
C17.	Continue to conduct and provide access to funding for research on how climate change could affect local agriculture.	EMR
C18.	Continue to support agricultural producers to adapt to the impacts of climate change, adopt low-carbon practices and use surface water and groundwater efficiently.	EMR

Area #6: Innovation



Northlight Innovation

Innovation is new and improved ways of doing something, whether it is how we generate and use energy, how we manage waste, how we create products or how we interact with one another. Innovation can reduce the environmental impacts of existing industries and support the development of new industries. It drives economic progress and increased productivity, and helps diversify the economy.

Our approach to innovation will see continued support for Yukon's businesses, innovators and entrepreneurs through funding, procurement and skills development. We will also work to make existing industries and activities more sustainable in the long-term, including how we think about and manage waste.

Innovation objectives at a glance

CO_2 ⚡ 🏭 $	Support innovation and green business practices.
CO_2 ⚡ 🏭 $	Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.
CO_2 ⚡ 🏭 $	Enhance the sustainability of Yukon's tourism industry.
CO_2 $	Improve how we manage our waste to move toward a more circular economy.

Support innovation and green business practices.

As we build a green economy, we will support innovation, local business development, and green business practices. Government funding and purchasing decisions will encourage businesses to use greener practices and build climate resilience into their operations, and will create demand for innovative clean technologies. We will also support businesses, organizations and communities interested in pursuing a range of projects that will support green economic development and climate resilience across Yukon. As local, national and global economies become greener, Yukoners will need new entrepreneurial, business and technical skills to fully participate in new economic opportunities. Ensuring Yukoners have these skills by predicting and adaptively assessing skills needs will help ensure equitable participation in the green economy.

The Government of Canada is working with provinces and territories to develop a Canadian greenhouse gas offset system. This system could create an economic opportunity for Yukon businesses, organizations and development corporations to generate and sell carbon offsets within Canada.

ACTIONS

I1.	Incorporate greenhouse gas emissions into the decision-making process for Department of Economic Development funding programs by 2022.	EcDev
I2.	Update the Government of Yukon's procurement policies and standards in 2020 to better support sustainable and local procurement.	HPW
I3.	Identify and develop options to address potential regulatory and policy barriers to the growth of green businesses in Yukon by 2023.	EcDev
I4.	Expand the range of relevant professional development offerings by 2023 to enable more Yukoners to participate in the green economy.	EMR
I5.	Create an award program by 2022 to recognize the achievements of local green businesses and organizations.	EcDev

Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.

Efforts to improve energy use in all phases of mining from planning to closure – such as using more efficient equipment or generating low-carbon energy onsite – can save money, lower greenhouse gas emissions, and support corporate social responsibility efforts. As demand for metals like copper, iron and lead increases to build more solar panels and other clean energy technologies, it is important that mining activities be energy efficient. We also need to make sure that mining activities are planned and carried out with climate change in mind. Thawing permafrost, increased rainfall and other climate change impacts affect the way a mine should be designed, operated and closed.

ACTIONS

I6.	Include new provisions in quartz mine licenses by 2022 that will ensure critical mine infrastructure is planned, designed and built to withstand current and projected impacts of climate change.	EMR
I7.	Require quartz mines to project their anticipated greenhouse gas emissions, identify measures to reduce emissions, and annually report greenhouse gas emissions through the quartz mine licensing process beginning in 2022.	EMR
I8.	Increase the Government of Yukon's participation in intergovernmental initiatives related to mine resiliency, low-carbon mining and innovation by 2021.	EMR
I9.	Establish an intensity-based greenhouse gas reduction target for Yukon's mining industry and additional actions needed to reach the target by 2022.	EMR & ENV

Enhance the sustainability of Yukon's tourism industry.

The Yukon Tourism Development Strategy, released in November 2018, establishes a vision for tourism to be a vibrant, sustainable component of Yukon's economy and society for the benefit of future generations. Sustainability is at the heart of the Tourism Development Strategy, with the aim for tourism to provide Yukon with sustainable, diversified growth that balances economic development with environmental, community and cultural values. We will support sustainable tourism by measuring and monitoring sustainable tourism development and taking action based on that information to ensure tourism growth supports healthy communities, preserves our natural environment for future enjoyment, and benefits Yukoners for generations to come.

ACTIONS

I10.	Establish and implement a framework to measure the sustainability of tourism development in Yukon by 2021.	TC
I11.	Develop and implement a system to track greenhouse gas emissions from Yukon's tourism industry by 2021.	TC

Improve how we manage our waste to move toward a more circular economy.

In a circular economy, products are designed to avoid waste and pollution, products and materials are used for longer before being recycled or composted, and natural systems are regenerated. It is different from the usual linear approach of making something, using it and throwing it away. Better waste management is a key part of a circular economy, and an element that Yukon can take action on. Improved waste management includes reducing waste, repairing or remanufacturing products so they can be used longer, recycling the materials in products to use them again and composting organic materials. Moving toward a more circular economy will support economic prosperity with as little environmental impact as possible.

Our targets are to reduce the amount of waste generated per person by 10 per cent by 2030, compared to 2020, and to increase the amount of waste diverted from the landfill per person to 40 per cent by 2025.

ACTIONS

I12.	Assess options for establishing a comprehensive waste diversion system in Government of Yukon buildings, including reuse, recycling, compost and e-waste collection by 2030.	HPW
I13.	Develop legislation that will enable the Government of Yukon to restrict or prohibit the production, supply or distribution of appropriate single use bags by 2021.	ENV
I14.	Design and implement a system for Extended Producer Responsibility by 2025 that will make producers responsible for managing materials through the lifecycle of a product.	ENV

Area #7: Leadership



Drummers at White Pass & Yukon Railway.

Our Clean Future aims to empower each and every government, business and individual to take a leadership role in building a healthy, prosperous Yukon for years to come. First and foremost, we will ensure the actions we take as governments in Yukon are consistent with our vision for a healthy, resilient future by considering climate change in all our actions. We will also empower Yukon businesses, organizations, individuals and families to be part of the solution.

Leadership objectives at a glance

	Ensure the goals of this strategy are incorporated into government planning and operations.
	Educate and empower youth as the next generation of leaders.
	Ensure Yukoners have the information needed to make evidence-based decisions.

Ensure the goals of this strategy are incorporated into government planning and operations.

Building a healthy, resilient future is not something that can be done in isolation from government policy. It is important that the goals of this strategy be integrated into all aspects of government planning and operations across Yukon to ensure the actions we take are consistent with our long-term vision.

Following recent upgrades to Yukon's school curriculum, students learn about climate change from Kindergarten to Grade 12. This includes learning about the causes of climate change, how climate change affects biodiversity and ecosystem health, and learning about climate change from the perspective of Yukon First Nations.

ACTIONS

L1.	Create a Clean Energy Act by 2023 that legislates our greenhouse gas reduction targets and our commitments to energy efficiency and demand-side management to hold the Government of Yukon accountable.	EMR
L2.	Incorporate a climate change lens into the decision-making process for major Government of Yukon policies, programs and projects by 2021.	ECO
L3.	Incorporate climate change risks into Government of Yukon departmental planning processes by 2022.	ENV
L4.	Incorporate greenhouse gas emissions and energy efficiency into the process for identifying and prioritizing Government of Yukon building retrofits and new construction projects by 2023.	HPW
L5.	Develop and offer climate change training for Government of Yukon employees by 2022.	ENV

Educate and empower youth as the next generation of leaders.

Youth will be most affected by the decisions we make today. Recognizing this, many Yukon youth have already become involved in climate change, energy and green economy initiatives. This strategy will support youth to continue being involved in these important areas, educating and empowering them to step forward as the next generation of leaders. Our approach to empowering and educating youth will respect and reflect Indigenous ways of knowing, doing and being.

ACTIONS

L6.	Create a Youth Panel on Climate Change in 2020 that will provide advice and perspectives to the Government of Yukon on climate change, energy and green economy matters that reflects the diversity of Yukon youth.	ECO
L7.	Provide mentorship opportunities for Yukon youth to participate in major international climate change and energy events with Government of Yukon staff beginning in 2023.	ENV
L8.	Continue to support land-based programs in the Yukon school curriculum that teach First Nations ways of knowing and doing to youth.	EDU



Chunday K'anat'a dancers.

Ensure Yukoners have the information needed to make evidence-based decisions.

Research, knowledge and information to inform evidence-based decision-making will continue to be an important part of our efforts on climate change, energy and green economy. To take effective action, we must understand the problems we are trying to solve and the solutions that are available. This understanding should be based on respectfully bringing together Indigenous, local and scientific knowledge and ways of knowing, doing and being. Over the course of this strategy, our knowledge will evolve with advances in research, science and technology, new local observations, and progress bringing together different perspectives and ways of knowing. Respectful information sharing and collaboration across governments, businesses, organizations and individuals will help us work together to build a clean future.

ACTIONS

L9.	Assess climate hazards and vulnerabilities to those hazards across Yukon every three to four years between 2020 and 2030 to prioritize climate change adaptation actions.	ENV
L10.	Support the Government of Canada's work to develop a pan-territorial climate hub by 2030 that will support access to climate data and projections for the north.	ENV
L11.	Begin participating in the National Forest Inventory monitoring program in 2022 to gather information about forest carbon stocks, potential biomass energy supply, pest and forest fire risks, and climate impacts on Yukon's forests.	EMR
L12.	Create easy access to technical information and lessons learned about climate change, energy and green economy for governments and stakeholders by 2021.	ENV
L13.	Launch a Yukon-wide information or social marketing campaign in 2021 that will educate Yukoners on greenhouse gas emissions, renewable energy, climate change adaptation, and other topics and highlight what Yukoners can do to support climate change initiatives.	ENV

Measuring our progress

The Government of Yukon will publicly report each year on the implementation of *Our Clean Future*. The annual progress reports will include:

- the status of each action in *Our Clean Future*;
- the key indicators of progress below as well as additional indicators or information for each action in the strategy;
- the latest 2030 greenhouse gas emissions forecast for Yukon; and
- any modifications to the actions in *Our Clean Future*.

Annual public reporting combined with a new Clean Energy Act to legislate key targets in *Our Clean Future* will ensure the Government of Yukon remains transparent and accountable to Yukoners as we rise to the challenge of addressing climate change.

Key progress indicators

Goal	Indicator	Target
Reduce Yukon's greenhouse gas emissions.	• Greenhouse gas emissions from transportation, heating, electricity generation, other commercial and industrial activities, waste and other areas.	• 30 per cent reduction by 2030, compared to 2010.
	• Greenhouse gas emissions intensity of mining.	• Target will be established by 2022.
Ensure Yukoners have access to reliable, affordable and renewable energy.	• Percentage of the electricity we use on the main Yukon electricity grid that is generated from renewable sources, calculated as a long-term rolling average.	• A long-term rolling average of 97 per cent by 2030.
	• Litres of fossil fuels used to generate electricity in off-grid communities.	• 30 per cent reduction by 2030, compared to 2010.
	• Percentage of energy used for heating that is from renewable sources.	• 50 per cent by 2030.
	• Greenhouse gas emissions from road transportation.	• 30 per cent reduction by 2030, compared to 2010.
Adapt to the impacts of climate change	• A set of qualitative and quantitative indicators that will reflect Yukon's resilience to climate change.	• Highly climate resilient by 2030.
Build a green economy	• Greenhouse gas emissions per person and per unit of real gross domestic product.	• A decrease from 2020 to 2030.

Key progress indicators will also be tracked and reported for each of the seven areas of *Our Clean Future* (see table at right). Targets associated with the indicators are noted in brackets.

Area	Indicator
Transportation	• Greenhouse gas emissions from transportation.
	• Number of zero emission vehicles registered in Yukon (4,800 by 2030).
	• Carbon intensity of transportation fuels.
	• Percentage of commuting trips made by drivers in single-occupant vehicles (55 per cent by 2031).
	• Number of road kilometres at risk of permafrost thaw that have undergone geohazard mapping.
	• Number of critical transportation corridors that have been analyzed for flood risk.
Homes and buildings	• Greenhouse gas emissions from heating fuel use.
	• Dollars invested in energy retrofits ($30 million each year on average).
	• Greenhouse gas emissions from Government of Yukon buildings (30 per cent reduction by 2030, compared to 2010).
	• Number of energy efficiency retrofits to residential, commercial and institutional buildings (2,000 by 2030).
	• Average percentage of new homes with energy performance above code.
	• Number of fossil fuel heating systems converted to smart electric heating systems (1,300 by 2030).
	• Number of commercial and institutional biomass energy systems (20 by 2030).
	• Gigawatt hours (GWh) of electricity demand avoided through demand-side management.
Energy production	• Greenhouse gas emissions from electricity generation.
	• Gigawatt hours (GWh) of energy generated from renewable sources.
	• Installed renewable electricity capacity in megawatts (MW).
	• Proportion of off-grid communities with operating renewable electricity projects (all off-grid communities by 2030).
	• Number of large-scale renewable heating projects.
Communities	• Proportion of at-risk communities that geohazard mapping has been completed for (all at-risk communities by 2024).
	• Proportion of at-risk communities that flood maps have been completed for (all at-risk communities by 2030).
	• Proportion of communities that Wildfire Protection Plans have been completed for (all communities by 2021).
People and the environment	• Number of cases of climate-related illnesses.
	• Proportion of Yukon communities with air quality monitoring (all communities by 2023).
	• Percentage of Yukoners that are food insecure.
Innovation	• Number of Yukoners that have participated in green economy professional development opportunities.
	• Proportion of quartz mines covered by new greenhouse gas reporting and climate resilience requirements.
	• The results of Yukon's sustainable tourism measurement framework.
	• Per capita waste generation in Yukon (10 per cent reduction by 2030, compared to 2020).
	• Per capita waste diversion in Yukon (40 per cent by 2030).
Leadership	• Number of Government of Yukon staff that have completed climate change training.

Prioritization

The objectives and actions in *Our Clean Future* went through a detailed prioritization process to make sure we are investing time and resources in the best ways to reduce greenhouse gas emissions, enhance energy security, adapt to the impacts of climate change and build Yukon's green economy.

Objectives

In fall 2018, the Government of Yukon worked with Indigenous and municipal partners to gather ideas about what a new climate change, energy and green economy strategy for the territory could include. Through public meetings, youth events, and input from stakeholders, experts and industry groups, numerous ideas were brought forward.

To decide which of these areas we should focus our efforts on, the Government of Yukon worked with Indigenous and municipal partners to jointly establish a set of decision-making criteria. The criteria were applied to each of the potential areas for action to inform which areas we should focus on. We used multiple criteria because deciding what to focus on is complex and cannot be determined by looking at any one factor alone.

Decision-making criteria

Effectiveness

How much could taking action in this area reduce greenhouse gas emissions, enhance energy security, increase climate resilience or build a green economy?

Economic effects

Could taking action in this area positively or negatively affect the economy?

Feasibility

How feasible it is to take action in this area over the next 10 years?

Societal effects

Could taking action in this area positively or negatively affect social equity and community wellbeing?

Participant interest

To what degree were participants in the public engagement interested in seeing action taken in this area?

Public health effects

Could taking action in this area positively or negatively affect public health?

Cost effectiveness

How cost effective would it be to take action in this area?

Environmental effects

Could taking action in this area positively or negatively affect the environment?

To assess each potential area of action using the criteria above, the Government of Yukon drew on several sources of expertise, including:

- "Yukon Greenhouse Gas Mitigation Analysis" by Vector Research that compiled climate change and energy programs and policies from other jurisdictions that may be appropriate to Yukon;
- "Yukon Greenhouse Gas Mitigation Analysis: Part II: Prioritization of Practical Greenhouse Gas Emissions Mitigation Measures" by Vector Research that estimated the cost per tonne and greenhouse gas reduction potential of various measures to reduce emissions;
- "Evaluation of Opportunities in a Green Economy in Yukon" by Research Northwest that identified the core components of Yukon's green economy and potential green economic opportunities;
- Early findings from the Government of Yukon's corporate climate change risk assessment regarding key climate hazards and areas of vulnerability that may be applicable to Yukon as a whole; and
- The Government of Yukon's Women's Directorate regarding potential societal effects.

Copies of the reports listed above can be found on Yukon.ca.

After applying the criteria to each potential area that we could focus on, the Government of Yukon brought a proposed list of focus areas to Indigenous and municipal partners for discussion. The final focus areas from that discussion became the objectives in *Our Clean Future*.

Actions

The Government of Yukon's actions in *Our Clean Future* were developed to work toward the objectives identified with Indigenous and municipal partners. The Government of Yukon's actions were informed by several factors, including:

- Policies and programs implemented in other jurisdictions, and the lessons they learned in the process;
- Lessons learned from previous and current climate change and energy initiatives in Yukon;
- Climate change and energy research and studies from Yukon and across Canada;
- Ideas and suggestions from experts, stakeholders, and industry members;
- Public interest in certain actions as communicated thorugh the first and second public engagements on *Our Clean Future*; and
- Energy-economy modelling completed by Navius Research.

Energy-economy modelling

The Government of Yukon worked with Navius Research to develop an energy-economy model for Yukon that can assess the possible greenhouse gas reduction and economic impacts of different actions to reduce emissions. The model can also identify ways to reduce greenhouse gas emissions most cost effectively.

The first step of model development was to calibrate the model based on Yukon's historical greenhouse gas emissions and various other pieces of information like energy use, the types of heating systems used in buildings, and economic activities.

The next step was to incorporate the greenhouse gas reduction policies and programs that were already in place in Yukon prior to *Our Clean Future* into the model, such as energy efficiency rebates offered by the Government of Yukon's Energy Branch. This resulted in a forecast of what Yukon's greenhouse gas emissions might look like if we continued with current initiatives only – referred to as the "reference case" or "business as ususal" scenario.

The final step of the modelling was to incorporate potential new policies and programs into the model. The resulting greenhouse gas reduction and economic impacts forecasted by the model were then used to tweak and finalize new policies and programs, and to estimate the total greenhouse gas reduction that we will achieve through the actions in *Our Clean Future*.

The energy-economy model will continue to be updated as we implement *Our Clean Future* to inform adjustments to the strategy to meet the 2030 greenhouse gas reduction target for Yukon.

For more information about the energy-economy modelling, please see the detailed report from Navius Research available through Yukon.ca.

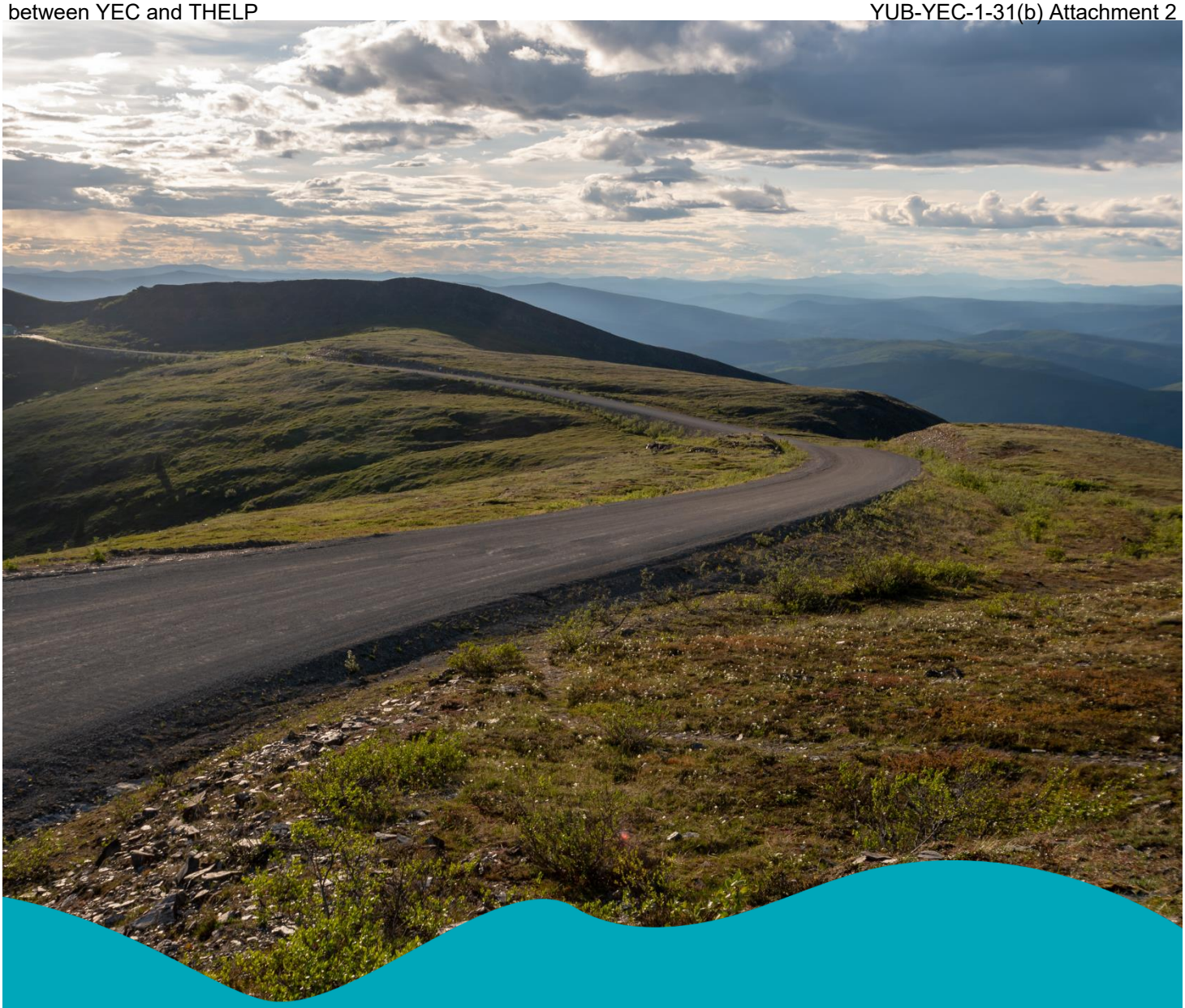
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Kusawa Lake.





Our Clean Future

A Yukon strategy for climate change, energy and a green economy

Draft for public review
November 2019

Yukon

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Our Clean Future

About the draft strategy

The Government of Yukon developed this draft strategy in partnership with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities throughout 2018 and 2019.

It sets out our collective vision, goals and values along with our strategic objectives over the next 10 years to address the climate change emergency and set us on a path toward a stronger, more sustainable future for Yukoners. This strategy is organized into six areas: transportation, homes and buildings, energy production, communities, innovation and leadership. Each area contains several objectives and actions for the next ten years.

This strategy has been informed by ideas we received from the public and stakeholders during a first round of engagement in fall 2018. For more information, please refer to the What We Heard report available on EngageYukon.ca.

This draft strategy only includes specific actions that the Government of Yukon will take to support each strategic objective at this time. We are continuing to work with our partners to explore further opportunities for action. As a result, additional actions may be included in the final strategy. The Government of Yukon's actions will be updated every three to four years to ensure the strategy remains current and relevant from now until 2030.

How to provide feedback

We are seeking feedback on the ideas in this draft strategy. What do you think of our proposed approach to address climate change, meet our energy needs and build a green economy? What are your ideas for how we can improve this strategy? To provide your input, visit EngageYukon.ca.

Our future

We live in a world that is rapidly changing. Climate change is affecting ecosystems, subsistence hunting and harvesting, leisure activities and many other aspects of our lives. Yukon's population is growing, along with our need for reliable, affordable and renewable energy to continue to power our lives, our work and our economy. New economic opportunities are emerging in the sustainable, green economy.

Across the North, we have a long history of coping with and adapting to changing, and sometimes harsh, conditions. First Nations and Indigenous languages and ways of life are intimately connected with the land, rivers and mountains that are home. Generation after generation, First Nations have built and passed along knowledge, skills and values shaped in part by the patterns of the landscape.

Our history of adaptation and resilience provides a strong foundation as we work together to address the changes to come. However, many of the changes we are experiencing now are unprecendented in terms of scope and speed, making it more important than ever to come together to share our collective knowledge and experiences and take action for a strong future.

Our vision is to come together as leaders to address climate change by building thriving, resilient communities powered by clean energy and supported by a sustainable green economy.

Countries around the world have committed through the Paris Agreement to keep global temperature rise below 2 degrees Celsius and to respond to the impacts of climate change. In Canada, cities, provinces, territories and the federal government are taking action to reduce greenhouse gas emissions and build greener economies powered by clean energy that will be more resilient and sustainable. Yukon will be part of this national and global shift. We will continue to work collaboratively with governments around the world to take collective action on this global issue.

Values

Our vision is supported by a set of core values. These values will shape the steps we take to build thriving, resilient communities.

Core value	How this value is reflected in the strategy
For all Yukoners We are building a brighter future for the collective, long-term benefit of all Yukoners today and for those to come, inclusive of ethnicity, culture, language, gender, sexuality, age, ability, education, income and other identity factors.	• Financial and technical support to help Yukoners participate in the green economy, such as rebates and low-interest financing. • Objectives and actions related to public transportation, human health and other areas that will have broad societal benefits.
Empower everyone We will foster partnerships, collaboration, information-sharing and capacity-building to empower governments, organizations, businesses and individuals to take action.	• Actions to work with First Nations and municipal governments on energy efficiency, renewable energy and food security projects. • Actions to improve information sharing between governments and with businesses and individuals.
Raise awareness All Yukoners should be aware of climate change, energy and the economy and how they can contribute to building a more sustainable, resilient future.	• Actions to raise awareness amongst businesses, individuals and youth, including awareness of the programs available to support their involvement in climate change, energy and the green economy.
Be accountable We will outline specific, measurable and time-bound actions to achieve our collective goals, along with the necessary human and financial resources to implement and monitor them.	• Once we have heard from Yukoners on this draft, the final strategy will include information about timelines, evaluation and costs.

Support reconciliation We will support reconciliation and strengthen relationships between Indigenous and non-Indigenous governments, organizations and individuals.	• Objectives that reflect the outcomes of a partnership process with Yukon First Nations, transboundary Indigenous groups and Yukon municipalities to develop this strategy. • Actions that support First Nations' involvement in energy efficiency, renewable energy and food security projects.
Make informed decisions We will make informed decisions, incorporating traditional, scientific and local knowledge.	• Actions to gather information that will help us make informed decisions.
Respect our natural environment We will recognize the inherent value and importance of our natural environment and prioritize solutions that harness natural capital and ecosystem services.	• Actions to safeguard wild species and their habitats.
No "one size fits all" approach Our actions must reflect Yukon's unique strengths and challenges.	• Actions that will support community-based projects that make sense in their local context. • As partnering Indigenous and municipal government and organizations take action, they may choose which objectives to focus on depending on the needs and priorities of their community.

Goals

Over the next 10 years, we will work toward four goals that will help us achieve our vision for a better future.



Reduce Yukon's greenhouse gas emissions.



Ensure Yukoners have access to reliable, affordable and renewable energy.



Adapt to the impacts of climate change.



Build a green economy.



Reducing greenhouse gas emissions

The issue

Climate change is primarily caused by the release of greenhouse gases – like carbon dioxide and methane – from human activities that burn fossil fuels. These activities range from driving vehicles and heating buildings to commercial and industrial processes. In Yukon, greenhouse gas emissions mostly come from transportation and heating, with a smaller amount from industry, electricity generation, waste and other areas.

To address climate change, everyone needs to participate: all levels of government, organizations, industry, businesses and individuals. While Yukon's total greenhouse gas emissions are relatively low because of our small population (0.1 per cent of Canada's emissions), our per person emissions of around 18 tonnes per person are the sixth highest in Canada and higher than many other countries. It is important that we play our part in reducing the greenhouse gas emissions that are causing climate change and impacting our northern way of life.

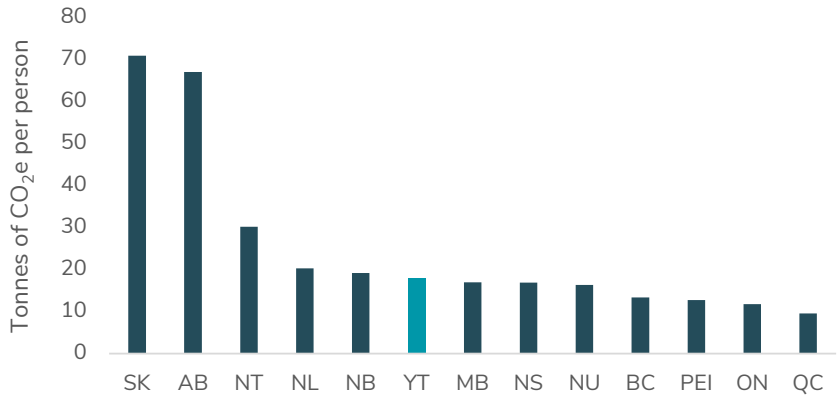


Figure 1. Greenhouse gas emissions per person by Canadian province and territory (2017).

Our target

By 2030, we will reduce Yukon's greenhouse emissions from transportation, heating, electricity generation, waste and other areas so that our emissions in these areas are 30 per cent lower than they were in 2010. This is an ambitious and achievable target that is aligned with Canada's international commitment under the Paris Agreement.

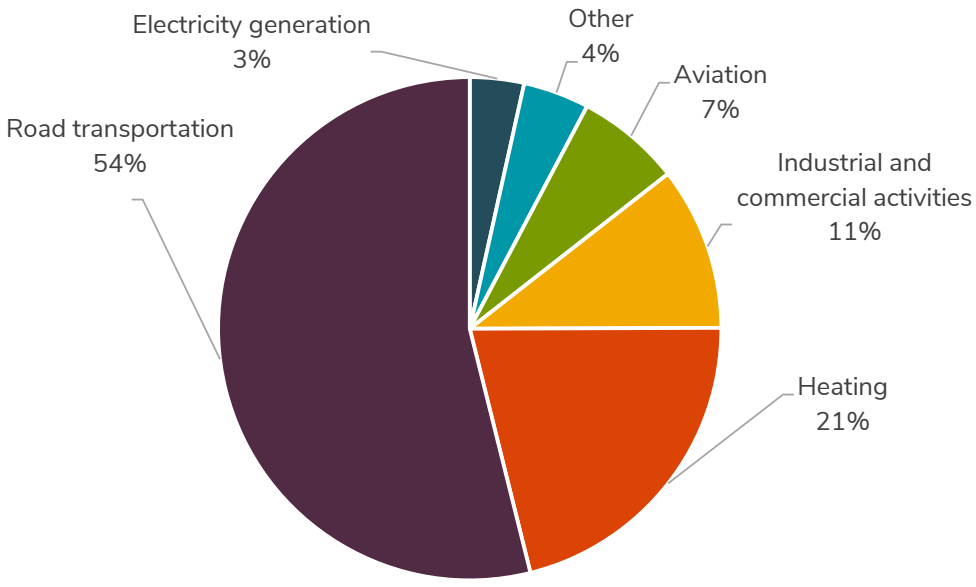


Figure 2. Yukon's sources of greenhouse gas emissions (2017).

How we will meet it

Reaching a 30 per cent greenhouse gas reduction target for Yukon will require extensive modernization to our road transportation and heating systems, which together contribute 75 per cent of Yukon's emissions. It will also require significant diversified investments in more renewable electricity generation, creating local jobs and economic opportunities. By reaching this target, we will inspire others by demonstrating that a remote, northern jurisdiction can achieve a significant reduction in greenhouse gas emissions.

We have learned several lessons since the last time greenhouse gas reduction targets were set for Yukon. In the 2012 Climate Change Action Plan Progress Report, twelve different targets were set for a variety of sectors. While the targets related to greenhouse gas emissions from buildings and electricity generation were met, the other targets were not met or could not be reported on due to a lack of available data.

Since that time, we have made improvements to how we gather and report greenhouse gas emissions data. We are now setting targets that we know we can track through available data. We have also conducted modelling work to help us set a greenhouse gas reduction target that is both ambitious and achievable and have built-in a process to update the actions in this strategy every three to four years to ensure we remain on track.

Mining plays a central role in the transition to a green economy. Minerals are vital to low carbon technologies – from batteries to wind turbines, solar panels and electric vehicles. Meeting an emissions intensity target will help Yukon's mining industry sustainably produce the materials needed for the global green economy.

Additional action on mining

In the past, Yukon's greenhouse gas emissions have gone up and down, driven in large part by the level of mining activity in the territory. While our greenhouse gas reduction target will ensure we see a decrease in emissions from transportation, heating and other areas, we also need a plan to address greenhouse gas emissions from mining and other industrial activities.

Over the next several months, we will work with industry to set an intensity-based target for mining that will see our mines produce fewer emissions of greenhouse gases across their lifecycle for every kilogram or kilotonne of material produced. This intensity-based target will encourage industry to look for innovative ways to reduce energy use and greenhouse gas emissions from mining, regardless of how many or few mines are in operation at any time. If mining were incorporated into Yukon's overall greenhouse gas reduction target, there is a risk that a decrease in mining activity could cause us to reach our target, resulting in less motivation to reduce greenhouse gas emissions from transportation, heating and other key areas.

Ensuring reliable, affordable and renewable energy

Electricity

The issue

In Yukon, we meet over 90 per cent of our electricity needs each year with clean, renewable power because of our large supply of hydroelectricity. As Yukon's economy and communities grow, and as Yukoners increasingly invest in electric vehicles and electric heating technologies – particularly in new buildings – demand for electricity will grow.

Our target

Moving forward, we will ensure that we continue to provide most of our electricity from renewable sources. For the main Yukon electricity grid, we will ensure that at least 93 per cent of the electricity we use comes from renewable sources, even as demand grows. For the communities that are not connected to the main electricity grid, we will reduce diesel use for electricity generation by 30 per cent by 2030, compared to 2010.

To make sure the lights turn on when we need them and that we are able to heat our homes – even on the coldest days of winter – we will also have the necessary backup power on hand. Today, fossil fuels like diesel and natural gas are best suited for backup power because they are quick and reliable. Over time, technological improvements and efforts to be more energy efficient will reduce the amount of fossil fuels we need to have as backup energy.

The Yukon Energy Corporation is working on a detailed renewable energy plan to identify projects that will help us reach the renewable electricity targets established in this strategy. The renewable energy plan will update the Yukon Energy Corporation's 2016 Integrated Resource Plan and will be informed by the work of an independent expert energy panel that is talking to Yukoners about specific renewable energy opportunities and challenges in Yukon.

How we will meet it

To meet Yukon's renewable electricity targets, we will need to invest in more electricity generation capacity, which could range from wind and solar to hydroelectricity projects. We may also need to upgrade electricity transmission and distribution infrastructure to support increased use of electricity for things like electric vehicle charging.

These investments will create local jobs and opportunities, but electricity rates could go up. This is in part because significant capital investments will be needed. It is also because the full costs of diesel and other fossil fuels – like air pollution, greenhouse gas emissions and fuel spills – are not reflected in the fees we currently pay for these energy sources.

The Government of Yukon will strive to minimize the impact of any electricity rate increases on Yukoners by helping individuals, families and businesses use energy more efficiently. We will also work with Yukon's electrical utilities to facilitate energy-efficient practices and reduce demand at peak times. This will reduce the amount of new electricity generation infrastructure that needs to be built and the related impacts on electricity rates.

Transportation and Heating

The issue

Two-thirds of the energy we use for transportation and heating comes from fossil fuels. Over the next ten years, we will reduce our reliance on fossil fuels in these areas. We will do this through efficiency improvements to reduce energy demand, switching to clean electricity for some of our transportation and heating needs, and developing local renewable heat sources like biomass energy.

Our target

By 2030, we will meet 40 per cent of our heating needs with renewable energy sources. For transportation, reaching the overall greenhouse gas target for Yukon will involve a significant reduction in transportation emissions because road and air transportation account for 61 per cent of Yukon's greenhouse gas emissions.

Adapting to climate change

The issue

We are already experiencing significant changes to our climate. Since 1948, temperatures in northern Canada have increased by 2.3 degrees Celsius, with temperature rise being most rapid in Yukon and the Northwest Territories[1]. This is close to three times the rate at which global temperatures are rising. Over the same period, rain and snowfall increased by six per cent in Yukon and has become more unpredictable[2].

Some climate change impacts we have experienced, and will continue to experience, are:

- Permafrost thaw, which damages buildings and roads, changes landscapes and affects ecosystems;
- More frequent extreme weather events, which can destroy habitat and homes and cause flooding;
- More severe forest fires, which pose a risk to communities and affect ecosystems and wildlife; and
- Glacier melt, which can affect river flow patterns, water temperature and aquatic health.

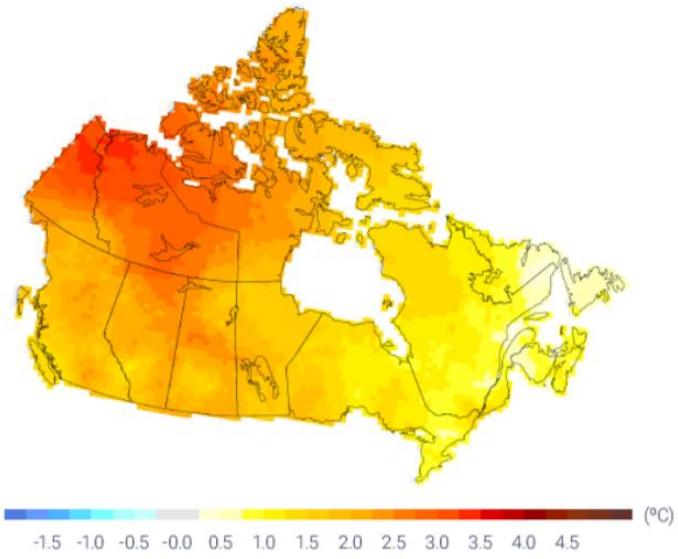


Figure 3. Change in annual temperature across Canada from 1948 to 2016. Figure from the Government of Canada[1].

Our target

We are taking action to adapt to climate change, including impacts we are already experiencing and those yet to come. We want to make sure that by 2030, Yukon communities are highly resilient to the impacts of climate change. To track progress toward this goal, we will work with Indigenous and municipal partners to establish a set of indicators to measure how resilient Yukon communities are.

How we will meet it

When planning for the changes we expect to see in the future, it is important to recognize that the range of possible climate impacts depends on global greenhouse gas emissions. To prepare for future conditions, we assume that global greenhouse gas emissions will continue along the current path when predicting the risks that we will face.

The actions we take through this strategy will benefit Yukoners no matter how much change we experience, because efforts to respond to climate change involve significant investment in people and communities.

A risk-based and human-centered approach

Not all individuals, households or communities will be affected the same by the changes that are coming. Our vulnerability to the impacts of climate change is affected by the condition of our homes, whether we rent or own, our ability to afford insurance, the health conditions we live with, and the presence of friends and family to support us in emergencies.

In this strategy, our approach to adaptation recognizes the importance of reducing the risks we all face while also working to improve human health, food security, and other factors like access to housing and stable employment that will make all Yukoners and Yukon communities more resilient.

We will also work to understand and reduce the impacts of climate change on Yukon's natural environment, including wildlife, plants, fish and ecosystems more generally. This work will complement broader efforts to conserve wildlife, protect biodiversity and manage forests sustainably. It will also make Yukon communities more resilient because intact natural systems provide protection from some climate change impacts.

The Intergovernmental Panel on Climate Change (IPCC) is the leading international scientific body on climate change. In its Fifth Assessment Report, the IPCC identified four "representative concentration pathways" (RCPs) that describe different levels of future climate warming depending on global greenhouse gas emissions. Currently, global greenhouse gas emissions are most consistent with the RCP8.5 pathway, which projects 2.6 to 4.8 degrees of warming globally by the end of the century.



Building a green economy

The issue

A green economy creates economic prosperity while protecting the environment in order to build a healthy, prosperous future. In a green economy, energy and other resources are used efficiently, with minimal waste. Economic activities and operations release fewer emissions of carbon dioxide and other gases. A green economy is also resilient and inclusive so that communities, businesses and individuals can adapt efficiently to the impacts of climate change and take advantage of new opportunities.

There are many opportunities for Yukoners as we build a green economy in the territory, alongside national and international efforts. As local, national and global demand for green goods and services increases, there are opportunities for Yukon innovators, entrepreneurs and businesses to supply clean energy and find ways to use energy more efficiently. The knowledge economy will grow as Yukoners come up with innovative solutions to local and global challenges. Efforts to use energy and other resources more efficiently will also reduce operating costs for Yukon businesses.

What we will do

Yukon's approach to a green economy focuses on:

- Helping Yukon businesses and individuals plan for, and benefit from, the economic opportunities that will arise as we take action on climate change and energy;
- Supporting innovation and the knowledge economy and recognizing the achievements of local green businesses and organizations; and
- Making it easier for businesses, communities and entrepreneurs to access funding and support for green projects across Yukon.

We will track our progress toward building a green economy by looking at changes to greenhouse gas emissions per person and greenhouse gas emissions per unit of gross domestic product over time.

Taking action

Our Clean Future: a Yukon strategy for climate change, energy and a green economy is organized into six areas:



Transportation



Homes and buildings



Energy production



Communities



Innovation



Leadership

Within each area, we include several objectives that reflect the priorities of the Government of Yukon as well as participating municipal and Indigenous partners. For more information about how the objectives were prioritized, please see page 60.

Each objective contributes to one or more of these four goals:



Reducing greenhouse gas emissions;



Ensuring Yukoners have access to reliable, affordable and renewable energy;



Adapting to the impacts of climate change; and



Building a green economy.

Actions

To reach each objective, we need to take specific, tangible actions. At the time of this public engagement, the draft strategy only contains the Government of Yukon's proposed actions. These actions are the Government of Yukon's top priorities for addressing climate change, meeting energy needs and building a green economy over the next ten years. For each action, the Government of Yukon department or agency responsible for leading the implementation of that action is listed for transparency and accountability.

Timing

The Government of Yukon's actions will be updated every three to four years to ensure the strategy remains relevant from now until 2030.

Government of Yukon departments and agencies

CS	Community Services
EcDev	Economic Development
EDU	Education
EMR	Energy, Mines and Resources
ENV	Environment
ECO	Executive Council Office
FIN	Finance
HSS	Health and Social Services
HPW	Highways and Public Works
JUS	Justice
TC	Tourism and Culture
YDC	Yukon Development Corporation
YEC	Yukon Energy Corporation
YHC	Yukon Housing Corporation

Partnership

The Government of Yukon will use this strategy to lead by example while also supporting First Nations, municipalities, businesses and individuals to take collaborative action to build a strong, healthy future.

To implement many of the Government of Yukon's actions in this strategy, we will continue to depend on partnerships with the federal government, using funding available to provinces and territories. In particular, we hope to receive continued federal support for improvements in clean transportation, building energy efficiency, renewable energy projects, emergency preparedness and response, and community adaptation.


Yukon in 2030
Here are some of the ways Yukon could look different in 2030 as a result of the objectives and actions in this strategy.
Our mining industry will produce fewer emissions of greenhouse gases per unit of production.
40 per cent of our heat will come from renewable energy.
Native species will be able to move across the landscape in response to climate change through a network of protected areas.
We will be better prepared to respond to emergencies.
More people will use public and active transportation.
Our homes and buildings will be substantially more energy efficient.
We will grow more of our food locally.
93 per cent of our electricity will be generated by hydro, wind, solar, biomass and other renewable sources.
Businesses will capitalize on opportunities for green innovation and entrepreneurship.
There could be over 6,000 zero emission vehicles in Yukon.

Measuring our progress

The Government of Yukon is developing a plan to evaluate our progress to make sure we reach our goals. This plan will include regular reporting to the public on the implementation of the actions in this strategy, our progress toward the objectives we have established, and where we are at in relation to our targets. More information about how we will measure our progress will be included in the final strategy.

Targets snapshot

Goal	Related targets
Greenhouse gas emissions	• By 2030, Yukon's greenhouse gas emissions from transportation, heating, electricity and other areas will be 30 per cent lower than they were in 2010.
Reliable, affordable and renewable energy	• 93 per cent of the electricity we use on the main Yukon electricity grid will come from renewable energy. • By 2030, we will use 30 per cent less diesel for electricity generation in off-grid communities. • By 2030, 40 per cent of the energy we use for heating will come from renewable sources.
Climate change adaptation	• All Yukon communities will be highly resilient to the impacts of climate change by 2030.
Green economy	• By 2030, we will see reductions in greenhouse gas emissions per capita and greenhouse gas emissions per unit of gross domestic product (GDP).

Reaching our targets

Working together

Yukoners will need to work together to reach our greenhouse gas reduction target and our goal for all Yukon communities to be highly resilient to the impacts of climate change by 2030. Recognizing this, *Our Clean Future* creates many opportunities for Yukoners to take part in reducing emissions, making Yukon more resilient, and building a green economy. Here are some of the ways you can participate and help ensure we are able to build the clean, resilient Yukon we want for the future.



Greenhouse gas reduction target

In 2017, the most recent year we have data for, Yukon's non-mining greenhouse gas emissions were 620 kilotonnes. This is an increase from our 2010 emissions of 590 kilotonnes. Based on modelling, we anticipate that Yukon's non-mining emissions could increase to 677 kilotonnes in 2030 if we do not

take action. As a result, to reach our 30 per cent greenhouse gas reduction target by 2030, we estimate that we need to reduce Yukon's greenhouse gas emissions by 264 kilotonnes.

However, forecasting what Yukon's greenhouse gas emissions could be in 2030 is very challenging. Future emissions depend on several factors, including population growth, the economy, and the success of the actions in this strategy, all of which are hard to predict. This makes it very important to track actual greenhouse gas emissions on a regular basis and be flexible and adaptive in our efforts.

Assuming that we need to reduce greenhouse gas emissions by 264 kilotonnes, we expect that the actions outlined in this strategy will get us three-quarters of the way there. The Government of Yukon is committed to closing the remaining gap over the next 10 years as new technologies become available and as we learn more about which actions are the most effective.

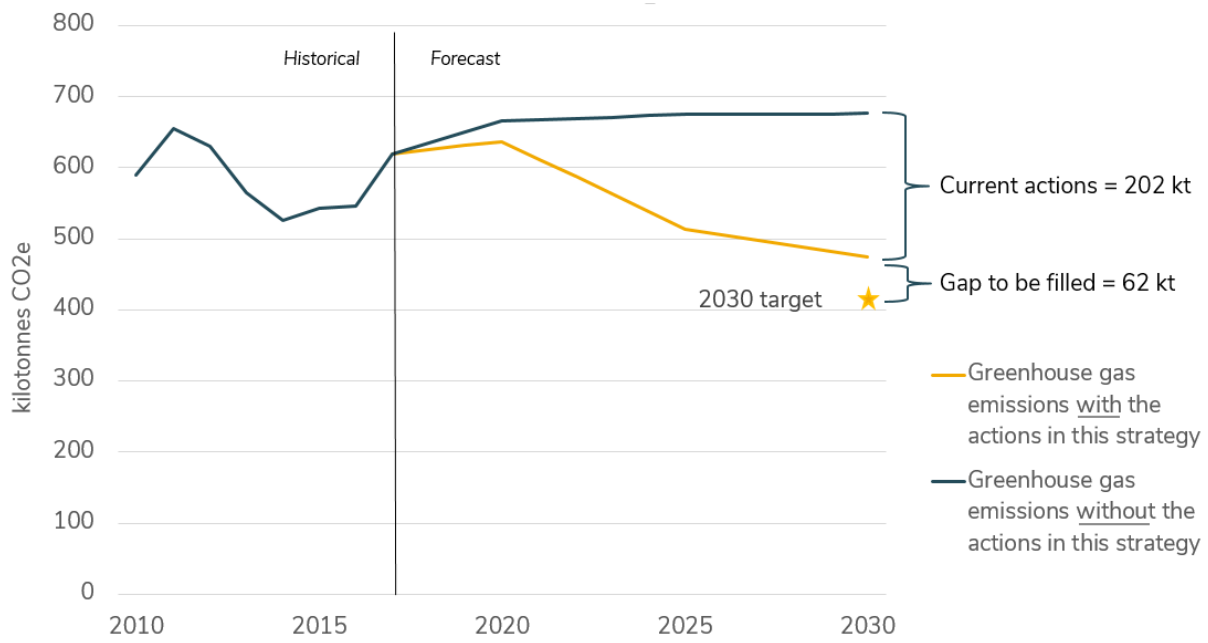


Figure 4. Historical and forecasted non-mining greenhouse gas emissions with and without the actions identified in this strategy.

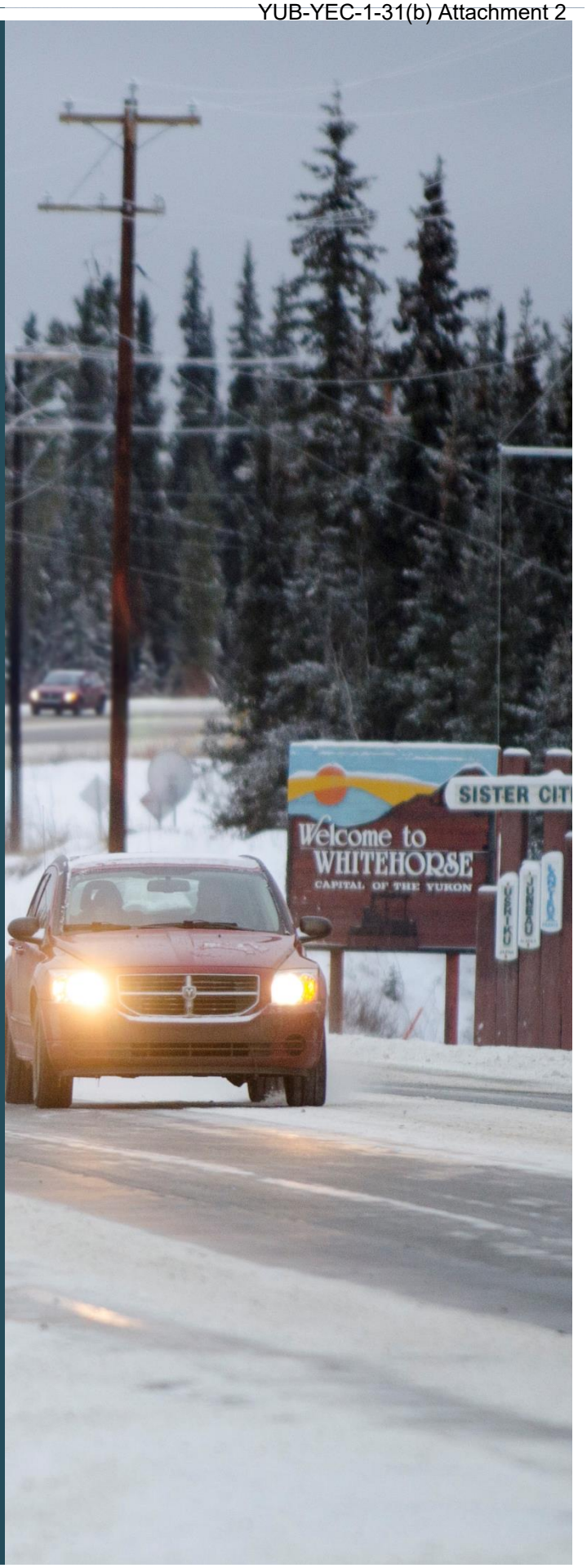
Moving forward, we will monitor greenhouse gas emissions and the success of our actions as we implement this strategy. Based on this information, we will update our actions in 2024 to help close the gap in meeting our 2030 greenhouse gas reduction target, as well as the other targets in this strategy. In 2027, we will complete another update based on the newest information on our progress.

Anticipated greenhouse gas reductions in 2030 in kilotonnes (kt)

Increasing the use of zero emission vehicles: • Targets for zero emission vehicles to be 10 per cent of light-duty vehicles sales in 2025 and 30 per cent in 2030. • Rebates for purchasing zero emission vehicles. • Commitment for half of all new cars purchased by the Government of Yukon to be zero emission vehicles.	6 kt
Increasing the use of public and active transportation.	6 kt
Using cleaner fuels for transportation: • Increasing the use of clean diesel in heavy duty transportation. • Increasing the use of ethanol as a clean gasoline alternative.	57 kt 11 kt
Making buildings more energy efficient: • Rebates and low-interest financing for energy efficiency retrofits. • Requiring new buildings to be significantly more energy efficient.	21 kt
Replacing fossil fuel heating systems with electric heat pumps in buildings that have been retrofitted to be more energy efficient.	9 kt
Conducting energy efficiency retrofits and installing renewable heating systems in Government of Yukon buildings.	8 kt
Using clean electricity: • Requiring at least 93 per cent of the electricity on the main Yukon grid to come from renewable sources. • Reducing the use of diesel for electricity generation in off-grid communities by 30 per cent through community-based renewable energy projects. • Substituting some of the diesel used to generate electricity with clean diesel alternatives like renewable diesel or biodiesel.	71 kt 10 kt 7 kt
Total*	**202 kt**
GHG reduction needed to reach 30 per cent target	**264 kt**

*The total does not match the sum of the invidual policies because of policy interactions where two or more policies contribute to the same greenhouse gas reduction.

Transportation

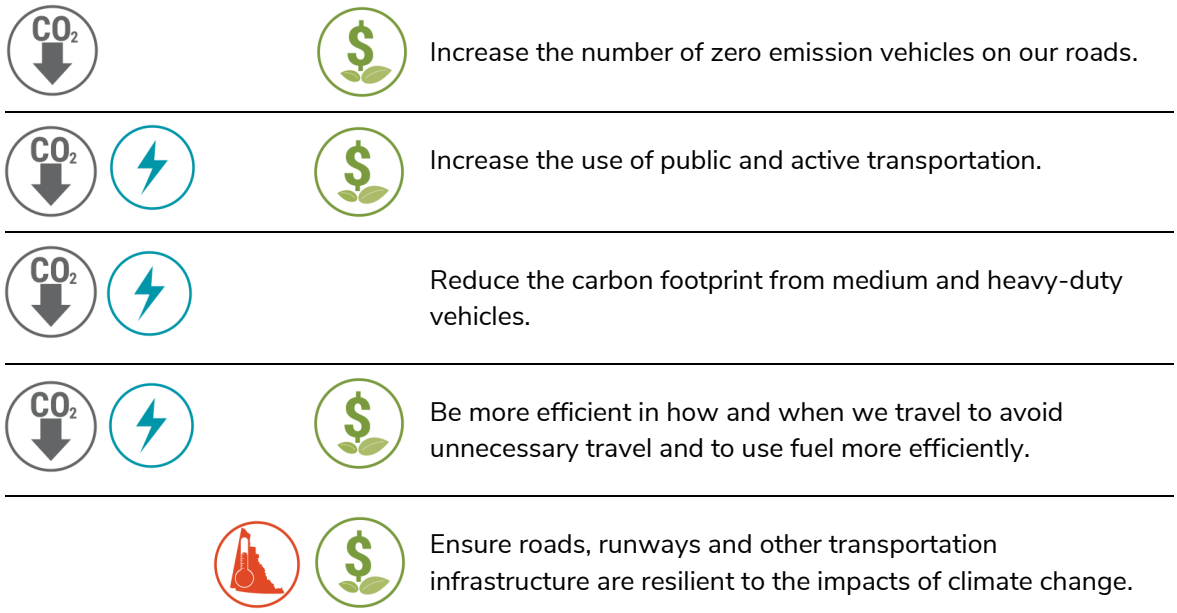


Area #1: Transportation

Currently, almost all the energy we use to meet transportation needs comes from fossil fuels. As a result, transportation is the largest source of greenhouse gas emissions in Yukon, contributing 62 per cent of total emissions. Close to 90 per cent of transportation emissions come from road transportation, with a relatively equal split between personal vehicles and commercial and industrial vehicles. The remaining transportation emissions are from aviation.

Our approach to transportation will make it easier for Yukoners to use clean forms of transportation, reducing fuel costs for individuals, families and businesses as well as greenhouse gas emissions. We will also respond to the impacts of climate change on our transportation systems to ensure Yukon's economy remains strong and resilient. Our transportation objectives are supported by efforts in other areas of this strategy that will reduce our dependence on imported fossil fuels and other products by supporting local goods and services.

Transportation objectives at a glance



Increase the number of zero emission vehicles on our roads.

Increasing the use of electric vehicles and vehicles with low or zero greenhouse gas emissions is one of the most significant ways we can reduce emissions. There are already several electric vehicles in Yukon, and they are a reliable and affordable transportation solution, even in our cold climate. Supporting a broader transition to zero emission vehicles will allow Yukoners to continue to go where and when they need to while reducing greenhouse gas emissions and improving air quality. It will be important for zero emission vehicle sales to come from local dealerships to support Yukon's green economy.

Yukoners drive about 16,000 kilometres each year. At this distance, the average Yukoner could save close to $2,000 a year in fuel costs by switching from a gasoline vehicle to an electric vehicle, depending on the vehicle make and model [3].

Our target for 2030 is to have over 6,000 zero emission vehicles registered in the territory – or approximately one in every six passenger vehicles on the road. Our commitment to meet at least 93 per cent of Yukon's electricity needs from renewable sources will ensure these vehicles are powered sustainably.

ACTIONS

1.	Work with local dealerships to ensure enough zero emission vehicles are available for purchase in Yukon to reach targets that zero emission vehicles will be 10% of light duty vehicle sales in 2025 and 30% in 2030.	EMR
2.	Ensure half of all new cars purchased by the Government of Yukon are zero emission vehicles.	HPW
3.	Provide a rebate to Yukon businesses and individuals who purchase eligible zero emission vehicles.	EMR
4.	Continue to install fast-charging stations across Yukon to make it possible to travel between all road-accessible Yukon communities by 2027.	EMR
5.	Work with the governments of British Columbia, Northwest Territories, and Alaska to explore options for installing electric vehicle charging stations to connect Yukon with BC, NWT, and Alaska.	EMR
6.	Provide financial incentives to support the installation of electric vehicle charging stations at multi-residential and commercial buildings.	EMR

7. Require new residential buildings in the greater Whitehorse area to be built with the electrical infrastructure to support Level 2 electric vehicle charging.	CS
8. Enable private businesses and Yukon's public utilities to sell electricity for the purpose of electric vehicle charging.	EMR
9. Conduct a public education campaign to raise awareness of the benefits of electric vehicles and how they function in cold climates.	EMR

Increase the use of public and active transportation.

Increasing the number of people who walk, bike and use public transit is another key way to lower greenhouse gas emissions. By reducing the number of people driving vehicles, investments in public and active transportation also reduce congestion, improve air quality and help people lead active, healthy lives. Making it easier to get around without a vehicle can also contribute to more inclusive communities by providing an accessible and affordable way to get from one place to another. While transportation options in and around Whitehorse are key to reducing greenhouse gas emissions, we will also look for public and active transportation solutions in and between Yukon's smaller communities.

ACTIONS

10. Provide financial incentives to encourage the purchase of electric bicycles for personal and business use.	EMR
11. Investigate the feasibility of using electric buses for public transportation.	CS & EMR
12. Explore opportunities to support municipal and First Nations partners with public transportation projects.	CS
13. Continue to incorporate active transportation in the design of highways and other Government of Yukon transportation infrastructure near communities.	HPW
14. Continue to offer flexible start times to make it easier for Government of Yukon staff to use public transit, active transportation and carpooling when operationally feasible.	ENV

Reduce the carbon footprint from medium and heavy-duty vehicles.

Yukoners rely heavily on goods brought up from southern Canada and around the world. While we are making progress toward meeting more of our needs locally, shipping of food, fuel, and other products will continue to be an important part of our lives and economy, given Yukon's relative remoteness. We also rely on medium duty vehicles like school buses, road clearing equipment and mail delivery vans to keep communities safe and accessible and to meet our daily needs. We will work to find efficiencies and reduce emissions from medium and heavy-duty vehicles.

ACTIONS

15. Replace older Government of Yukon heavy-duty fleet vehicles and incorporate fuel efficiency into purchasing decisions to reduce greenhouse emissions and fuel costs.	HPW
16. Increase the use of clean diesel alternatives like biodiesel and renewable diesel, such as through a 20% renewable content standard.	EMR & ENV
17. Establish a financial incentive to support the purchase of short-haul medium and heavy-duty electric vehicles for commercial applications within Yukon.	EMR
18. Pilot the use of idle-reduction and fuel efficiency technologies to reduce the fuel consumption of heavy-duty vehicles.	EMR
19. Work with the Government of Canada to offer courses on efficient driving for medium and heavy-duty vehicle operators.	HPW

Be more efficient in how and when we travel to avoid unnecessary travel and to use fuel more efficiently.

Sometimes we make decisions about how or when we travel that are not as efficient as they could be. We may idle our vehicles or drive too fast. We may choose to drive alone, rather than carpooling with friends or coworkers. We may bring more luggage than we need on a holiday, affecting the fuel efficiency of the plane when we fly. Sometimes we might travel somewhere for a meeting or conference when we could have participated by phone or video.

In some cases, these decisions can't be changed. However, we can sometimes make an effort to travel smarter or not travel at all. We can invest in technology that will allow us to move ideas rather than people. When we do travel, we can make sure we do so efficiently. Making efforts to be more efficient in how and when we travel can help Yukoners save money while also reducing greenhouse gas emissions, cutting back on congestion, making roads safer and reducing air pollution.

Safer and more efficient driving behaviours like slower acceleration, more measured braking and driving the speed limit can increase the fuel efficiency of your vehicle by up to 35 per cent.

ACTIONS

20. Increase the use of ethanol as a clean gasoline alternative, such as through a 10 per cent renewable content standard.	EMR & ENV
21. Expand the Government of Yukon's video and teleconferencing systems, raise awareness of the options available, and require employees to consider these options when requesting permission for work travel.	HPW
22. Develop systems to coordinate Government of Yukon staff travelling by vehicle within Yukon.	HPW
23. Develop guidelines for the Government of Yukon vehicle fleet to ensure appropriate vehicles are used and incorporate fuel efficiency into purchasing decisions to reduce greenhouse gas emissions and fuel costs.	HPW
24. Expand the Government of Yukon's telehealth services to improve access to healthcare in Yukon communities while reducing greenhouse gas emissions from travel to and from Whitehorse.	HSS
25. Conduct a public education campaign to raise awareness of the benefits of public and active transportation and efficient driving practices.	ENV

Ensure roads, runways and other transportation infrastructure are resilient to the impacts of climate change.

Climate change is already affecting Yukon's transportation infrastructure. Thawing permafrost damages our roads, runways and bridges and increases maintenance costs. Landslides, flooding,

forest fires and other natural hazards can wash out roads, cutting communities off from critical supply routes. It is important that we address the impacts of climate change on our transportation infrastructure to ensure we stay safe and connected and to protect our economy and livelihoods.

ACTIONS

26. Develop and implement climate-resilience guidelines for road construction and transportation infrastructure projects built by or receiving capital funding from the Government of Yukon.	HPW
27. Update and expand geohazard maps to cover all major transportation corridors.	EMR
28. Analyze flood risk along all major transportation corridors at risk of flooding and continue to incorporate flood risk information into the design of transportation infrastructure.	ENV & HPW
29. Conduct climate risk assessments of all major transportation infrastructure projects above $10 million[1], such as through the federal Climate Lens assessment.	HPW

[1] $10 million dollars is the threshold established by the Government of Canada for climate risk assessments through the Climate Lens.

Homes and buildings



Area #2: Homes and buildings

The Government of Yukon will invest $30 million dollars on average each year for energy efficiency improvements to homes and buildings. This will include low-interest financing and rebates, support for First Nations and municipal governments, and retrofits to Government of Yukon buildings.

Many Yukoners spend a lot of time inside, whether at home, at work or at school. How we design, use and heat these buildings affects our comfort, safety, productivity, health and finances.

Right now, many buildings use more energy than they need to and heating buildings accounts for 21 per cent of Yukon's greenhouse gas emissions. Taking steps to use less energy saves money, stimulates the economy and supports green jobs in construction. Improving energy efficiency is a key step toward significant greenhouse gas reductions through heating highly efficient buildings with low-carbon energy sources like biomass and geothermal.

The Government of Yukon will lead by example in this area by undertaking energy efficiency retrofits and installing renewable heating systems to reduce greenhouse gas emissions from Government of Yukon buildings by 8 kilotonnes by 2030.

At the same time as we make our buildings more efficient, we can ensure they are designed to be more resilient to fires, floods, permafrost thaw and heat stress. This will reduce long-term repair and maintenance costs, health risks like mould, and improve public safety.

Homes and buildings objectives at a glance



Improve the energy efficiency and climate resilience of existing homes and buildings.



Ensure new homes and buildings are built to be low-carbon and climate-resilient.



Increase the use of biomass and other renewable energy sources for heating.



Use energy more efficiently and better align energy supply and demand.

Improve the energy efficiency and climate resilience of existing homes and buildings.

Many existing homes and buildings can be improved to use less energy and to be more resilient to the impacts of climate change. The energy efficiency of our homes and buildings is affected by insulation, draftiness, and the mechanical and electrical systems we use for heat and power. Similarly, how many trees surround our buildings affects our vulnerability to forest fires while our foundation and roof affect resilience to flooding and permafrost thaw. Taking action to improve our homes and buildings will lead to many benefits for Yukoners, from saving money on heating and electricity to improving comfort and safety.

The amount of money paid by insurance companies in Canada for property damage due to severe weather has increased from $400 million per year in the 1980s to over one billion dollars per year. This is contributing to substantial increases in premiums for home and property insurance across Canada.

ACTIONS

30. Conduct retrofits in Government of Yukon buildings to reduce energy use and greenhouse gas emissions.	HPW
31. Continue to retrofit Government of Yukon social housing and staff housing to reduce energy use in these buildings by 30 per cent.	YHC
32. Continue to gather information about climate change impacts on Government of Yukon buildings to maintain safe conditions for occupants and to inform decisions for major construction projects.	HPW
33. Provide upfront financing to support energy efficiency retrofits and actions to improve building resiliency.	EMR & CS
34. Continue to provide comprehensive incentive programs for home energy retrofits, commercial building retrofits, and energy efficient appliances and other products to reduce energy use.	EMR
35. Continue to work with Yukon First Nations to retrofit First Nations housing to be more energy efficient.	EMR

36. Continue to provide financial support to Yukon First Nations and municipal governments to pursue major energy retrofits to their government buildings across Yukon.	EMR
37. Evaluate options to encourage landlords and/or tenants to pursue energy efficiency improvements to rental units.	EMR
38. Work with the Government of Canada to develop and implement a low-carbon model building code suitable to northern Canada that will reduce energy use and greenhouse gas emissions from existing buildings.	CS & HPW
39. Review the *Insurance Act* to ensure Yukoners can access adequate insurance for fires, floods and permafrost thaw.	CS

Ensure new homes and buildings are built to be low-carbon and climate-resilient.

It is important that new buildings are low-carbon and climate-resilient from the beginning. Making sure new homes and buildings are built to energy efficient standards and with the potential impacts of climate change in mind will save money for homeowners and building owners, decrease pressure on the electrical grid, reduce greenhouse gas emissions and improve safety and comfort.

Across Canada, governments are working together toward net-zero energy ready buildings. This means buildings constructed in 2032 and later will be designed to be so energy efficient they could be heated and powered with just the energy from onsite renewables. In general, this means that new buildings in Canada will be designed to be at least 50 per cent more energy efficient than currently required by the 2015 National Building Code. The Government of Yukon will work with the Governent of Canada to ensure new codes are suitable to northern Canada. Close to two-thirds of new homes in Whitehorse are already being built near this standard thanks to rebates from the Energy Solutions Centre.

ACTIONS

40. Work with the Government of Canada to develop and implement building codes suitable to northern Canada that will aspire to see all new residential and commercial buildings be net zero energy ready by 2032.	CS & HPW
41. Publish a building standards manual for the design and construction of new Government of Yukon buildings that will improve energy efficiency and reduce greenhouse gas emissions.	HPW
42. Require buildings to be constructed to be more climate resilient by adopting and enforcing standards related to permafrost thaw, flooding, fires and other climate change impacts.	CS
43. Conduct climate risk assessments of all major building projects over $10 million that are built or funded by the Government of Yukon.	CS & HPW
44. Continue to provide rebates for new homes that are built to energy efficient standards.	EMR

Increase the use of biomass and other renewable energy sources for heating.

Increasing how much of our heating needs are met through renewables will reduce our greenhouse gas emissions and support the local economy. In this strategy, we will focus on increasing the use of wood and other forms of biomass energy in large commercial and government buildings with significant heating demand. Sustainably harvested biomass is a low-carbon and renewable energy source. It can help reduce our greenhouse gas emissions while supporting jobs in our local biomass industry and decreasing the risk of forest fires around Yukon communities. Our focus on heat includes geothermal and other renewable heat options that may become available in the future. We will also focus on efficient electric heating technologies like air source and ground source heat pumps, that use less electricity than conventional resistance electric heat.

Heat pumps are a form of electric heating in which heat from the air or ground outside the building is absorbed, concentrated and then released inside the building. Heat pumps are significantly more energy efficient than standard electric resistance heaters like electric baseboards. They can also be used to cool buildings during the summer.

ACTIONS

45. Install renewable heat sources such as biomass energy in Government of Yukon buildings to reduce greenhouse gas emissions and create long-term demand for renewable heating.	HPW
46. Establish a program to support the replacement of fossil fuel heating systems with electric heat pumps in buildings that have been retrofitted to be more energy efficient, with a target of 1,500 buildings over 10 years.	EMR
47. Continue to provide technical and administrative support to First Nations governments and development corporations to switch to biomass and other renewable heating systems.	EMR
48. Continue to provide rebates to install biomass and other renewable heating systems.	EMR
49. Identify regulatory improvements that could support the growth of Yukon's biomass energy industry during the review of the *Forest Resources Act*.	EMR
50. Regulate air emissions from biomass burning systems to minimize the release of harmful air pollutants.	ENV
51. Conduct a lifecycle analysis of biomass energy use in Yukon to identify recommended forest management practices to guide sustainable and low-carbon biomass harvesting.	ENV
52. Continue to use residual biomass fibre harvested during forest fuel management projects to provide a source of renewable biomass energy and increase the resilience of communities to wildland fire risk.	CS & EMR

Use energy more efficiently and better align energy supply and demand.

Energy use is affected by how much we heat our buildings, whether we leave the lights on when we leave the house, what appliances we buy, and other behaviours. Using energy more efficiently will help Yukoners save money and reduce greenhouse gas emissions. It is also important to align the timing of when people use energy with when energy is available to us through demand-side management. For example, we can shift energy use away from peak times to other times when fewer people are using energy.

ACTIONS

53. Direct the Yukon Utilities Board to allow Yukon's public utilities to pursue cost-effective capacity demand-side management measures.	YDC
54. Install individual electrical meters at Government of Yukon social and staff housing to encourage tenants to use energy more efficiently.	YHC
55. Conduct a pilot project to evaluate the use of smart devices to shift customers' energy demand to off-peak hours.	YDC
56. Continue to conduct outreach and education to encourage Yukoners to use energy more efficiently.	EMR & YHC

Energy Production



Area #3: Energy production

While close to 93 per cent of the electricity we generate in Yukon comes from renewable sources, only 26 per cent of the heat energy we use is from renewable sources, with the rest coming from non-renewable sources like diesel and propane. Overall, about 20 per cent of the energy we use in Yukon comes from renewable resources.

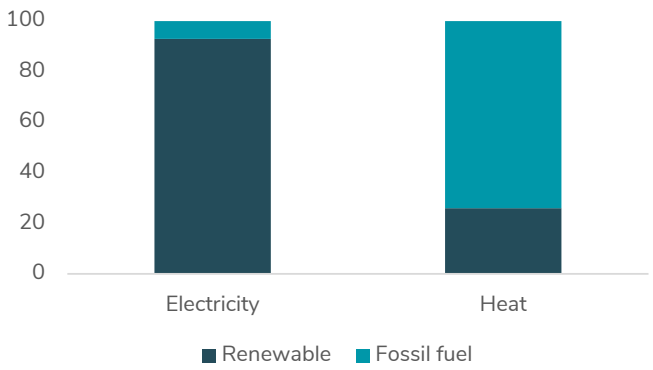


Figure 5. The percentage of electricity and heat energy that is produced by renewable sources and fossil fuels (2016).

Our approach to energy production will see more renewable energy produced for both heating and electricity. This will allow us to continue to heat and power our lives with clean energy while supporting local jobs across Yukon, decreasing our dependence on diesel, and reducing our greenhouse gas emissions. Our efforts to produce more energy from renewable sources as well as our actions to make our homes and buildings more energy efficient will minimize the amount of diesel and natural gas we need to have on hand as backup energy.

At the same time, we will take action to make our electricity generation, distribution and transmission infrastructure resilient to the impacts of climate change so Yukoners continue to have access to safe and reliable power.

Electricity objectives at a glance

	Increase the supply of electricity generated from renewable sources.
	Support local and community-based renewable energy projects for heating and electricity.
	Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

Increase the supply of electricity generated from renewable sources.

It will be important to increase the amount of electricity we produce from renewable sources as demand grows. While most of our electricity currently comes from hydro, we also have other renewable energy sources available like wind, biomass, solar and geothermal. Producing more of our electricity with local renewable energy will make us more self-sufficient and less vulnerable to changing fuel prices. Making sure we continue to supply most of our electricity through renewable sources is key to reducing our greenhouse gas emissions.

Through the Government of Yukon's Independent Power Production Policy and Micro-generation Program, Yukon communities and households have been generating clean electricity and selling power to the grid. Participating households in the Micro-generation Program have earned close to $700 per year on average by selling excess electricity to the grid.

ACTIONS

57.	Require at least 93 per cent of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	EMR & YDC
58.	Substitute some of the diesel used to generate electricity with clean diesel alternatives like biodiesel and renewable diesel.	EMR & ENV
59.	Update the *Public Utilities Act* to ensure an effective and efficient process for regulating electricity in Yukon.	EMR & JUS
60.	Pursue opportunities to install renewable electricity systems on Government of Yukon buildings and at remote historic sites co-managed by the Government of Yukon and Yukon First Nations.	HPW & TC

Support local and community-based renewable energy projects.

Local and community-based renewable energy projects create jobs and opportunities across Yukon, support self-sufficiency and help Yukoners be part of the clean energy economy. Through this strategy, we will support communities and individuals to produce local renewable energy for heating and

electricity, while creating opportunities for local businesses and contractors. Our target is to have an operating independent power production project in each off-grid community by 2025. We will also increase our knowledge of renewable and low-carbon energy sources that may be available in Yukon.

ACTIONS

61.	Continue to provide financial and technical support for First Nations and municipal governments and community organizations to undertake community-led renewable energy projects.	YDC
62.	Continue to implement the Independent Power Production Policy that enables Yukon's public utilities to purchase electricity from independent power producers, including Yukon First Nations and communities, and increase the Standing Offer Program limit from 20 GWh to 40 GWh to support additional projects.	EMR
63.	Develop models for First Nations to economically participate in renewable electricity projects developed by Yukon's public utilities.	YDC
64.	Continue to enable Yukoners to connect renewable energy technologies to their homes and businesses and export surplus energy to the electrical grid through the Micro-generation Program.	EMR
65.	Continue to provide rebates to support the installation of renewable energy systems for heating and electricity in residential, commercial and institutional buildings.	EMR
66.	Develop legislation to regulate geothermal energy development in Yukon.	EMR
67.	Continue to conduct research into the potential to use geothermal energy in Yukon for heating and/or electricity.	EMR
68.	Research the potential to use nuclear energy in Yukon, including small modular reactors.	EMR

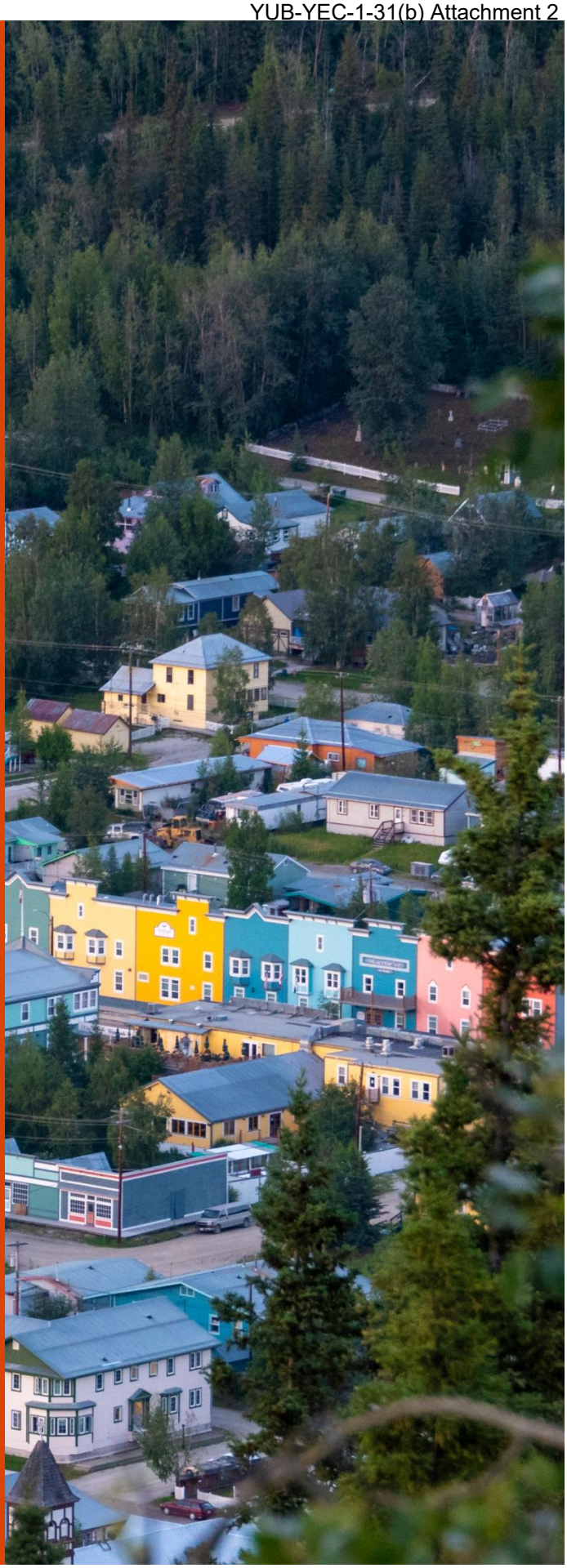
Ensure electricity generation, transmission and distribution infrastructure is resilient to the impacts of climate change.

The impacts of climate change and extreme weather events can negatively affect electricity infrastructure like power lines. Climate change is also affecting rain, snowfall and glacier melt in Yukon, which in turn can impact our hydro-based electricity system. The Government of Yukon, through the Yukon Energy Corporation, is responsible for the safe and effective management of our electrical systems. Proactive climate change risk management is an operating imperative. This involves conducting research, forecasting future conditions, identifying risks and opportunities, developing adaptation options, and incorporating climate change into long-term planning and decision making.

ACTIONS

69.	Continue existing partnerships with academia, government, First Nations, and NGOs to research and understand key impacts of climate change on the electricity sector.	YEC
70.	Use in-flow forecasting models to incorporate climate change data into short, medium and long-term water forecasts for renewable hydroelectricity generation.	YEC
71.	Design, construct and maintain all electricity infrastructure using best available methods to avoid permafrost degradation.	YEC
72.	Continue to incorporate updated flood probability and intensity considerations into dam safety programs and reviews.	YEC
73.	Implement a glacier monitoring program to improve our ability to predict the impacts of glacier melt on hydrological systems and hydroelectricity generation.	ENV

Communities



Area #4: Communities

Yukon is home to many unique, vibrant communities where we live, work, play and celebrate our cultures. This strategy takes proactive steps to ensure our communities will be strong and resilient into the future. Our communities will increasingly be places where people walk, cycle and use public transportation to get around and where local businesses thrive. We will be more resilient to the impacts of climate change, grow and eat more locally produced food, and continue to celebrate our cultures and traditions.

Communities objectives at a glance



Design our communities to be low-carbon and resilient to the impacts of climate change.



Ensure we are prepared for emergencies that are becoming more likely due to climate change.



Supply more of what we eat through sustainable local harvesting and food production.



Maintain our ability to safely engage in traditional and cultural activities.



Protect and enhance human health and wellbeing in a changing climate.



Respond to the impacts of climate change on wild species and their habitats.

Design our communities to be low-carbon and resilient to the impacts of climate change.

The ways our communities are designed affects how easy it is to walk to work, take public transit, or use renewable energy sources for heating and electricity. The design of communities and the underlying infrastructure also affects our ability to provide critical services like healthcare, clean and safe drinking water and waste management. Moving forward, we will focus on densifying communities rather than expanding outwards and make sure our homes are close to the places where we work and play. We will ensure that our communities are designed in ways that reduce our vulnerability to forest fires, permafrost thaw, flooding, drought and other natural hazards that are expected to worsen with climate change.

Building infrastructure to be climate-resilient adds about three per cent to the upfront cost. However, this investment pays back at about four times the amount invested due to lower repair costs and a longer useable lifespan[4]. Engineers and planners can follow the Government of Canada's Climate Lens guideline to help them design resilient infrastructure.

ACTIONS

74. Update and expand geohazard and floodplain maps to cover all Yukon communities, where appropriate, and assess how many buildings and other structures are currently located in areas with high geohazard or flood risk.	EMR & ENV
75. Conduct a review of best practices for developing walkable, bike-friendly, transit-oriented communities and develop guidelines that can be used by the Government of Yukon and partners.	ENV
76. Develop and implement climate-resilience guidelines for community design and infrastructure development projects built by or receiving capital funding from the Government of Yukon.	CS
77. Continue to conduct detailed climate change risk assessments of all major community infrastructure projects over $10 million that are built or funded by the Government of Yukon.	CS

78. Make recommendations to consider the impacts of climate change in regional land use and local area planning processes and, consistent with those plans, ensure communities are designed to be climate-resilient through the Government of Yukon's development permitting and zoning processes.	EMR
79. Provide technical and administrative assistance to First Nations and municipal governments to prepare integrated asset management plans that will reduce costs, attract businesses and investment to communities and increase climate resilience.	EMR

Ensure we are prepared for emergencies that are becoming more likely due to climate change.

Climate change is increasing the likelihood of emergencies like severe forest fires and floods. Taking action to reduce the risk of these events, and ensuring we are prepared if they do happen, is critical. Through this strategy, we will work to build climate-resilient communities across Yukon and to have systems in place to effectively predict and respond to fires, floods and other emergencies like water shortages or landslides that may threaten Yukon communities.

Emergency preparedness is a good investment. As one example, for every dollar invested in effective early warning systems for floods, fires or heatwaves, taxpayers save ten dollars on average in avoided damages.[4]

ACTIONS

80. Improve our ability to predict floods and forest fires by using updated earth observation platforms, expanding our network of automated weather stations and using modelling tools, and improve early warning systems for flooding.	ENV & CS
81. Develop and implement Wildfire Protection Plans for Yukon communities that outline recommended forest fuel management activities like FireSmarting to reduce forest fire risk.	CS
82. Increase the capacity in Yukon Wildland Fire to prevent wildfires through forest fuel reduction activities and to respond to extended fire seasons.	CS

83. Work with First Nations and municipal governments to develop emergency management plans for all Yukon communities informed by all-hazard community and critical infrastructure assessments, including plans to provide animal shelters during emergency evacuations.	CS & HSS
84. Work with First Nations and municipal governments to deliver emergency management programming for all Yukon communities, including initiatives to raise awareness of wildfire and flood risk and what Yukoners can do to be more resilient.	CS
85. Develop a territorial disaster financial assistance policy to support recovery from natural disasters that result in extensive property damage or disruption to the delivery of essential goods and services.	CS

Supply more of what we eat through sustainable local harvesting and food production.

Harvesting and producing more of the food we eat locally increases food security, contributes to the economy, and reduces how much food we need to ship into the territory. Local harvesting activities include subsistence hunting, gathering and fishing. Local food production can include community greenhouses and gardens, backyard gardens, larger-scale agriculture and farming and small-scale animal husbandry. All these forms of local harvesting and food production have an important role to play in a resilient, sustainable future.

The 2016-2021 Local Food Strategy for Yukon supports a more developed and sustainable local food system in the territory. *Our Clean Future* highlights the Government of Yukon's continued commitment to many relevant initiatives in the Local Food Strategy, including community food production.

ACTIONS

86. Continue to provide access to funding for community gardens, greenhouses and animal husbandry projects, especially in rural communities.	EMR
87. Continue to provide technical advice to assist First Nations and municipal governments with their agricultural and animal husbandry projects.	EMR

88. Continue to research how climate change could affect local agriculture in the future.	EMR
89. Continue to assist agricultural producers to respond to the impacts of climate change, adopt low-carbon practices, and use surface water and groundwater efficiently through technical advice, access to funding, and supportive infrastructure.	EMR & YDC
90. Regularly gather data on food insecurity to understand how many Yukoners are food insecure and why.	HSS

Respond to the impacts of climate change on wild species and their habitats.

Climate change is putting pressure on wild species and their habitats. Species ranges are projected to shift, snowpacks may become deeper, and streams are anticipated to change in flow, temperature and sediment levels. Extreme weather events, changes to the availability of prey and forage and conditions favourable to new and invasive species will negatively affect native species and existing ecosystems, adding to the cumulative stress they are experiencing. In response, they may migrate to a new location, adapt, persist or decline. For species that are used for subsistence, this can affect when and where people are able to harvest food. It is important that we better understand how climate change is affecting the natural environment and take action to minimize the impacts on wild species, their habitats, and the people that depend on them.

ACTIONS

91. Continue to improve our understanding of how climate change will impact watersheds, including water quality, quantity and habitat for fish and other wild species.	ENV
92. Continue to build our knowledge of how climate change is affecting ecosystems, wild species and their habitats.	ENV & EMR
93. Identify and monitor key species that will provide an indication of the impacts of climate change on Yukon ecosystems.	ENV

94. Continue to apply landscape conservation science to build a network of protected areas and other lands that allow native species to move, adapt and survive in the face of climate change.	ENV
95. Continue to track new and invasive species to Yukon that could impact ecosystems and biodiversity.	ENV

Maintain our ability to safely engage in traditional and cultural activities.

Many people go out on the land to hunt, fish, pick berries, travel from one community to another, and pursue other traditional and cultural activities. Climate change is threatening the safety of some of these activities. For example, changing trail and weather conditions are making it more dangerous to go out on the land. Climate change is also affecting sites that hold particular cultural and historic importance. We will take steps to understand how climate change is affecting cultures and traditions – using traditional, local and scientific knowledge – and respond appropriately to ensure long-term cultural sustainability.

ACTIONS

96. Increase search and rescue capacity through training, retention and volunteer recruitment.	CS
97. Continue to offer hunter education courses to promote environmental stewardship and safety on the land.	ENV
98. Continue to raise awareness of changing bear hibernation habits and how to stay safe in bear country.	ENV
99. Continue to address the impacts of climate change on historic and cultural sites across Yukon.	TC
100. Work collaboratively with First Nations and the Inuvialuit to develop a strategy to address the impacts of climate change on heritage sites on the North Slope.	TC

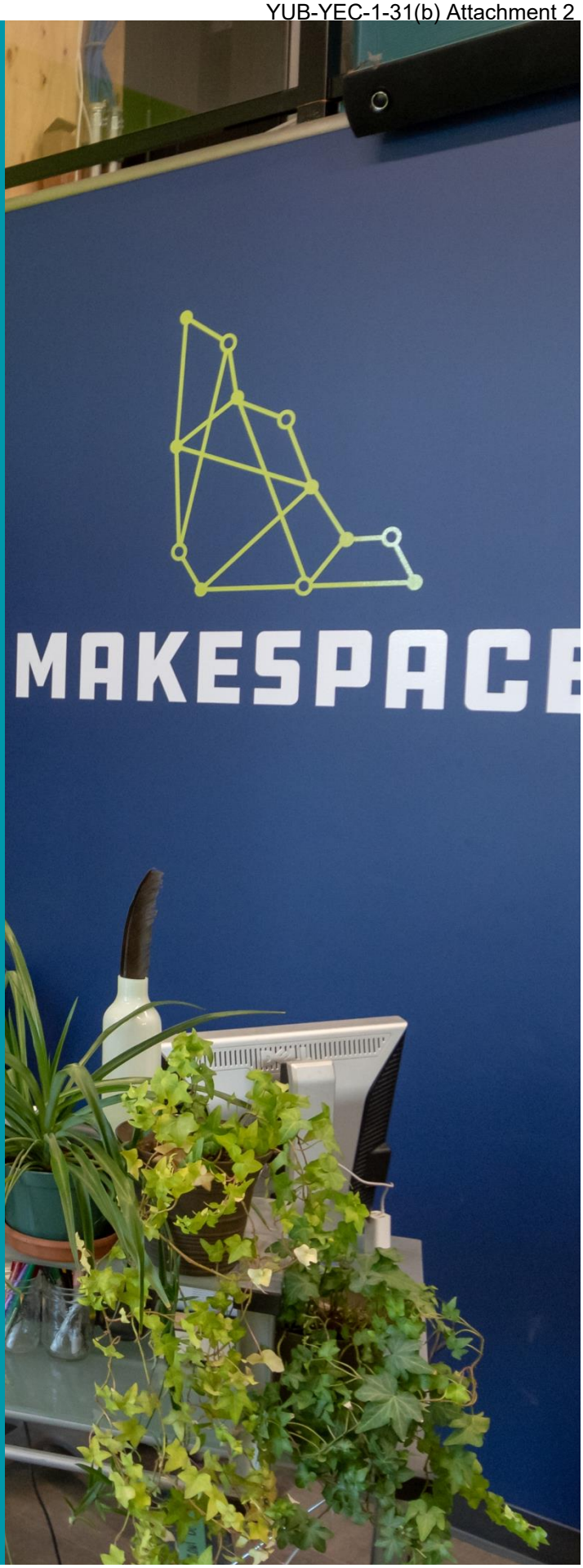
Protect and enhance human health and wellbeing in a changing climate.

Climate change affects human health in many ways. Health may be affected directly, such as impacts from extreme weather, or indirectly, such as the impacts of climate change on the environment. Our health and wellbeing also affects how much we are personally impacted by climate change and how quickly we are able to bounce back. We will act to reduce the negative impacts of climate change on human health by strengthening community resilience, enhancing food security, improving our ability to identify mental and physical health impacts of climate change and adapting to changing conditions.

ACTIONS

101.	Train health and social service care providers to identify and respond to the physical and mental health impacts of climate change.	HSS
102.	Develop and implement a system to track cases of climate-related illnesses like heat stroke, respiratory illness, and vector-borne diseases.	HSS
103.	Continue to monitor concentrations of particulate matter in the air from biomass burning and forest fires.	ENV
104.	Make clean air shelters available to Yukoners to provide a place to breathe clean air during periods of intense wildfire smoke.	HSS

Innovation



Area #5: Innovation

Innovation is new and improved ways of doing something, whether it is how we generate and use energy, how we manage waste, how we create products or how we interact with one another. Innovation can reduce the environmental impacts of existing industries and support the development of new industries. It drives economic progress and increased productivity, and helps diversify the economy.

Our approach to innovation will see continued support for Yukon's businesses, innovators and entrepreneurs through funding, procurement and skills development. We will also work to make existing industries and activities more sustainable in the long-term, including how we think about and manage waste.

The Government of Canada's price on carbon pollution is supporting innovation by encouraging individuals and businesses to switch to lower carbon alternatives and create new alternatives. The Government of Yukon is returning all carbon pricing revenues received from the Government of Canada to Yukon individuals, businesses and governments.

Innovation objectives at a glance



Support innovation and green business practices.



Ensure Yukoners have the skills to participate in the green economy.



Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.



Improve how we manage our waste to move toward a more circular economy.

Support innovation and green business practices.

As we build a green economy, we will support innovation, local business development, and green business practices. Government funding and purchasing decisions can encourage businesses to use greener practices and build climate resilience into their operations, and will create demand for innovative clean technologies. We will also support businesses, organizations and communities interested in pursuing a range of projects that will support green economic development and climate resilience across Yukon.

ACTIONS

105. Consider greenhouse gas emissions as part of the decision-making process for Department of Economic Development funding programs.	EcDev
106. Support sustainable and local procurement through updates to the Government of Yukon's procurement policies and standards.	HPW
107. Identify and develop options to address potential regulatory and policy barriers to the growth of green businesses in Yukon.	EcDev

Ensure Yukoners have the skills to participate in the green economy.

As local, national and global economies become greener, Yukoners will need new entrepreneurial, business and technical skills to fully participate in new economic opportunities. Ensuring Yukoners have these skills will help Yukon individuals and businesses across Yukon to participate in the opportunities associated with building a green economy.

ACTIONS

108. Continue to provide training for Certified Energy Advisors who are able to evaluate the energy efficiency of homes and buildings.	EMR
109. Continue to provide training for tradespeople, builders, and other interested individuals to develop the skills needed to retrofit and maintain buildings to energy efficient standards.	EMR

110. Continue to improve science, technology, engineering, arts and math (STEAM) education in Yukon schools.	EDU

Reduce the carbon intensity of mining and ensure mining projects are prepared for the impacts of climate change.

Efforts to improve energy use in all phases of mining from planning to closure – such as using more efficient equipment or generating low-carbon energy onsite – can save money, lower greenhouse gas emissions, and support corporate social responsibility efforts. As demand for metals like copper, iron and lead increases to build more solar panels and other clean energy technologies, it is important that mining activities be energy efficient. We also need to make sure that mining activities are planned and carried out with climate change in mind. Thawing permafrost, increased rainfall and other climate change impacts affect the way a mine should be designed, operated, and closed.

ACTIONS

111. Ensure critical mine infrastructure is planned, designed and built to withstand current and projected impacts of climate change throughout all phases of mining through the quartz mine licensing process.	EMR
112. Require quartz mines to project their anticipated greenhouse gas emissions, identify measures to reduce emissions, and annually report greenhouse gas emissions through the quartz mine licensing process.	EMR
113. Provide financial support for energy audits of mines to identify opportunities to reduce energy use and save money.	EMR
114. Continue to support targeted research on ways to reduce the carbon footprint from mineral exploration, development and closure activities, including options to use alternative energy sources at mine sites.	EMR
115. Continue to work with the mining industry to encourage and support the use of low-carbon and green practices and technologies in exploration, development and closure.	EMR

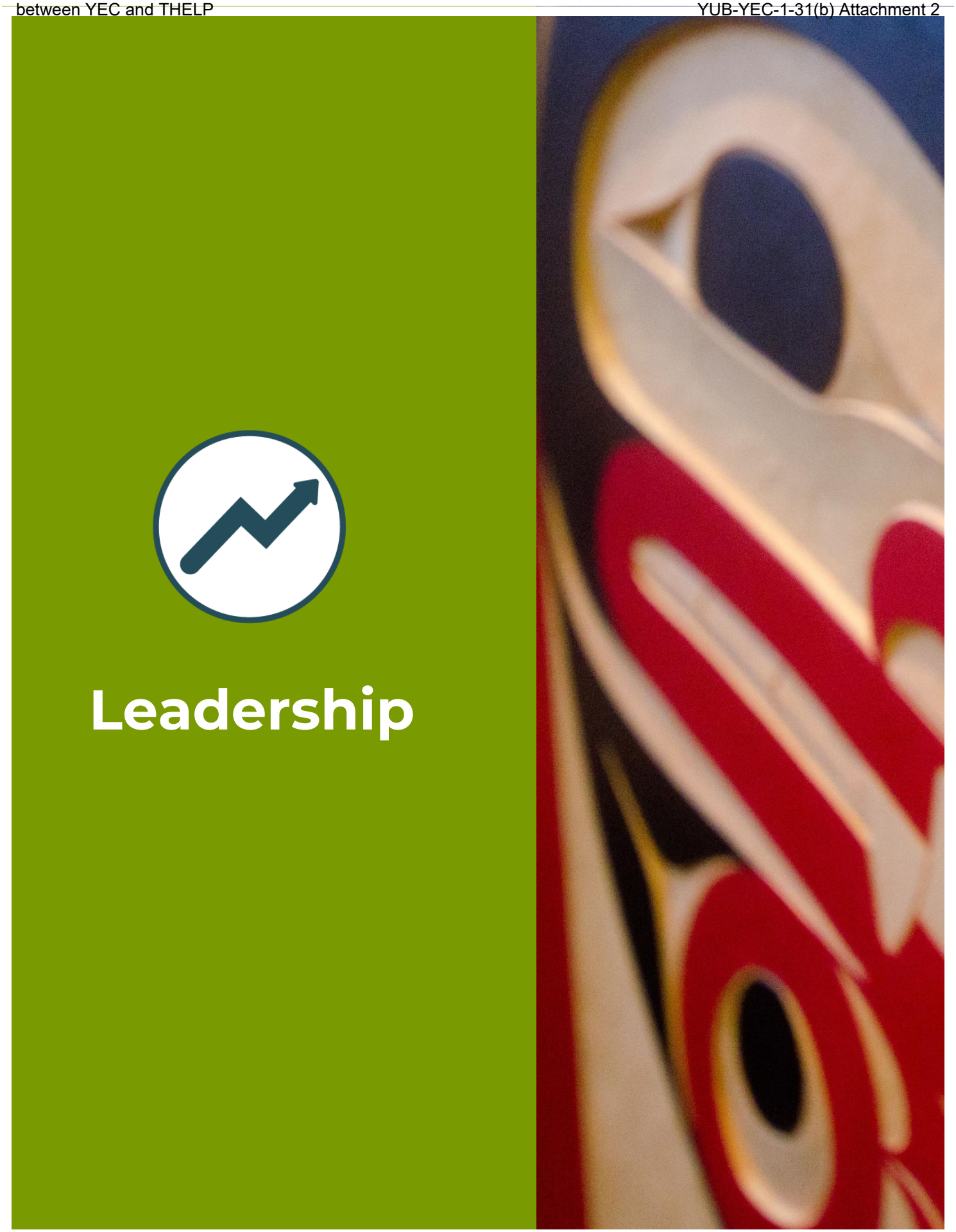
116. Increase the Government of Yukon's participation in intergovernmental initiatives related to mine resiliency, low-carbon mining and innovation.	EMR & ENV

Improve how we manage our waste to move toward a more circular economy.

In a circular economy, products are designed to avoid waste and pollution, products and materials are used for longer before being recycled or composted, and natural systems are regenerated. It is different from the usual linear approach of making something, using it and throwing it away. Better waste management is a key part of a circular economy, and an element that Yukon can take action on. Improved waste management includes reducing waste, repairing or remanufacturing products so they can be used longer, recycling the materials in products to use them again and composting organic materials. Moving toward a more circular economy will support economic prosperity with as little environmental impact as possible.

ACTIONS

117. Assess options for establishing a comprehensive waste diversion system in Government of Yukon buildings, including recycling, compost and e-waste collection.	HPW
118. Continue to increase the types of materials with recycling surcharges under the *Designated Materials Regulation* to increase waste diversion and generate more funding for recycling operations.	ENV & CS
119. Work towards a system for Extended Producer Responsibility that would make producers responsible for managing materials across the lifecycle of a product.	ENV & CS
120. Continue outreach and education activities aimed at reducing solid waste and increasing waste diversion.	ENV & CS
121. Conduct a lifecycle assessment of the best ways to deal with the waste generated in Yukon from an economic and environmental perspective to inform future actions.	CS


Leadership

Area #6: Leadership

Our Clean Future: a Yukon strategy for climate change, energy and a green economy aims to empower each and every government, business and individual to take a leadership role in building a healthy, prosperous Yukon for years to come. First and foremost, we will ensure the actions we take as governments in Yukon are consistent with our vision for a healthy, resilient future by considering climate change in all our actions. We will also empower Yukon businesses, organizations, individuals and families to be part of the solution.

Leadership objectives at a glance



Ensure the goals of this strategy are incorporated into government planning and operations.



Educate and empower youth as the next generation of leaders.



Increase public awareness of this strategy and how businesses and individuals can make a difference.



Ensure Yukoners have the information needed to make informed decisions.

Ensure the goals of this strategy are incorporated into government planning and operations.

Building a healthy, resilient future is not something that can be done in isolation from government policy. It is important that the goals of this strategy be integrated into all aspects of government planning and operations across Yukon to ensure the actions we take are consistent with our long-term vision.

ACTIONS

122.	Create a Clean Energy Act that legislates our greenhouse gas reduction targets, renewable energy generation targets and our commitment to energy efficiency and demand-side management to hold the Government of Yukon accountable to the commitments in this strategy.	EMR
123.	Consider greenhouse gas emissions and climate change adaptation in major Government of Yukon policies, programs and projects by applying a climate change lens to decision-making.	ECO & ENV
124.	Continue to evaluate the risks that climate change poses to the Government of Yukon's operations and implement strategies to address those risks.	ENV
125.	Incorporate greenhouse gas emissions and energy efficiency into the process for identifying and prioritizing Government of Yukon building retrofits and new construction projects.	HPW
126.	Develop and promote climate change training for Government of Yukon employees.	ENV
127.	Continue to assist First Nations and municipalities to identify, implement and access federal and Government of Yukon funding for climate change and energy projects.	EMR
128.	Continue to monitor progress and report on the effectiveness of our actions in meeting targets, reducing greenhouse gas emissions and adapting to the impacts of climate change through the Government of Yukon's Climate Change Secretariat.	ENV

Educate and empower youth as the next generation of leaders.

Youth will be most affected by the decisions we make today. Recognizing this, many Yukon youth have already become involved in climate change, energy and green economy initiatives. This strategy will support youth to continue being involved in these important areas, educating and empowering them to step forward as the next generation of leaders. Our approach to empowering and educating youth will acknowledge traditional knowledge and Indigenous ways of knowing and doing.

ACTIONS

129.	Create a Youth Panel on Climate Change that will provide advice and perspectives to the Government of Yukon on climate change, energy and green economy matters.	ENV
130.	Provide mentorship opportunities for Yukon youth to participate in major climate change conferences or events with Government of Yukon staff.	ENV
131.	Continue to integrate information about climate change impacts and adaptation into the Yukon school curriculum.	EDU
132.	Continue to support land-based programs in the Yukon school curriculum that teach First Nations ways of knowing and doing to youth.	EDU

Increase public awareness of this strategy and how businesses and individuals can make a difference.

The collaborative actions of businesses and individuals are key to reaching the goals of this strategy. It is businesses and individual Yukoners who will decide whether to retrofit their business or home to reduce energy use, buy an electric vehicle or start a new green economy venture. This strategy contains many initiatives that will help Yukoners do these things and more. In order to take action, Yukon businesses and individuals need to understand what they can do and what resources are available to assist them. It is also important to recognize and celebrate our achievements.

To become a leader in sustainable tourism, Yukon is implementing a sustainability framework through the Tourism Development Strategy that measures the impacts of tourism development to ensure it balances economic growth with healthy communities and safeguarding of the environment.

ACTIONS

133.	Implement a Yukon-wide information campaign about climate change, energy and green economy.	ENV
134.	Raise awareness of funding programs that can support green businesses and encourage applications to these funds.	EcDev
135.	Create a recognition program to recognize the achievements of local green businesses and organizations.	EcDev
136.	Implement an education campaign for Government of Yukon building occupants and visitors to encourage more energy efficient behaviours.	HPW
137.	Provide accessible information on how to improve energy efficiency, use renewable energy, reduce wildfire and flood risk, reduce water consumption, and build safely on permafrost.	ENV & EMR

Ensure Yukoners have the information needed to make informed decisions.

Research will continue to be an important part of our action on climate change, energy and green economy. To take effective action, we must understand the problems we are trying to solve and the solutions that are available. Our understanding of these things will continue to evolve over the course of this strategy with advances in research, science and technology. We also need to share the information we already know, as well as the new information we will gather. Information sharing and collaboration across governments, businesses, organizations and individuals will help us work together to build a better future.

ACTIONS

138.	Conduct regular assessments of the impacts of climate change on Yukon communities and evaluate the costs and benefits of responding to these impacts to inform future efforts.	ENV
139.	Conduct annual energy assessments of Government of Yukon buildings to identify further opportunities for energy efficiency and greenhouse gas reductions.	HPW
140.	Share technical information and lessons learned about climate change, energy and green economy with governments and stakeholders across Yukon using Yukon.ca and the Open Data Portal.	ENV
141.	Regularly meet with stakeholders to share information and receive feedback on energy-related policies, programs and projects.	EMR
142.	Regularly report on the impacts climate change could have on Yukon's economy.	FIN

Prioritization

The objectives in this strategy were developed with Indigenous and municipal partners by using a set of criteria to prioritize what the strategy should focus on. These criteria helped us make informed decisions about the best places to invest our time and resources. We used multiple criteria because deciding what to focus on is complex and cannot be determined by looking at any one factor alone.

Decision-making criteria

Core criteria

Effectiveness
How much could this contribute to reaching our four goals?

Feasibility
How feasible it is to take action in this area over the next 10 years?

Participant interest
To what degree were participants in the public engagement interested in seeing action taken in this area?

Cost effectiveness
How cost effective would it be to take action in this area? For greenhouse gas reduction initiatives, we considered the cost per tonne of greenhouse gases reduced.

Additional criteria

Economic effects
Could taking action in this area positively or negatively affect the economy?

Societal effects
Could taking action in this area positively or negatively affect social equity and community wellbeing?

Public health effects
Could taking action in this area positively or negatively affect public health?

Environmental effects
Could taking action in this area positively or negatively affect the environment?

With Indigenous and municipal partners, we used these criteria to evaluate each of the areas that we could take action on. Based on this evaluation, we decided which areas we should focus on, which areas we should evaluate further, and which should not be a priority for this strategy.

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[1] Government of Canada, 2019. Canada's Changing Climate Report. https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/energy/Climate-change/pdf/CCCR_FULLREPORT-EN-FINAL.pdf

[2] Streicker, J., 2016. Yukon Climate Change Indicators and Key Findings 2015. Northern Climate ExChange, Yukon Research Centre. https://www.yukoncollege.yk.ca/sites/default/files/inline-files/Indicator_Report_Final_web.pdf

[3] This number was calculated based on the fuel efficiency of an electric vehicle (Chevy Malibu) and a gasoline vehicle (Chevy Bolt), a gasoline price of $1.40 per litre, and an electricity rate of 0.129 cents per kilowatt hour.

[4] Global Comission on Adaptation, 2019. Adapt Now: A Global Call for Leadership on Climate Resilience. https://cdn.gca.org/assets/2019-09/GlobalCommission_Report_FINAL.pdf

ISSUE: **Hyperlinks**

REFERENCE: **Application, footnotes 22 and 24, page 18, PDF page 21**

PREAMBLE: **The Board has previously determined that hyperlinked documents are unacceptable as, over time, the links may be broken.**

QUESTION:

a) Please provide the hyperlinked documents referred to in footnotes 22 and 24 in PDF form.

ANSWER:

(a)

See Attachment 1 and Attachment 2 to this response.

10-Year Renewable Electricity Plan Technical Report

DECEMBER 2020

yukon energy

Executive Summary

Demand for electricity is growing in Yukon. There is an existing gap today between the available dependable capacity on the grid and the amount of electricity Yukoners require during a winter peak under emergency conditions. To continue providing most of the territory's energy from renewable sources and to accommodate the increased demand for electricity, Yukon Energy Corporation (YEC, Yukon Energy) must invest in new dependable renewable electricity sources that add firm winter capacity to the grid. This will allow YEC to continue meeting Yukoners' growing demands for renewable electricity – even on the coldest and darkest of days – while also supporting Yukon government's emission reduction targets.

This plan outlines a portfolio of key projects and partnerships needed by 2030 to address the substantial demand for renewable electricity that will result from ongoing economic growth of the Territory, and from the policies and actions outlined in the Yukon government's draft *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*. In this strategy, the government has mandated that an average of 93% of electricity generated on the grid must be produced from renewable sources and includes specific actions to electrify the territory's transportation and heating sectors.

In order to conduct this analysis, YEC updated its load forecast (the projected energy and demand requirements of Yukoners) based on recent learnings from cold weather peaks and incorporated the electrification actions of the Yukon government's *Our Clean Future* strategy to estimate the resulting increased demand. YEC used this load forecast, along with the inventory of existing generation and projects under development, to calculate the gap between the energy and demand requirements and available resources. Using updated technical and cost information on potential resources, the company then conducted a portfolio analysis to evaluate which renewable resource options could best address this gap, across a range of scenarios. The goal of this portfolio analysis was to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon.

The result is the updated Future-Focused Portfolio. Included in this portfolio are resources which are planned or currently under development. These ongoing projects include: Whitehorse Hydro uprates at WH2 and WH4, the battery energy storage system, renewable energy purchases from Independent Power Producers through the Standing Offer Program, solar energy from the Micro-Generation program, the Southern Lakes and Mayo Lake enhanced storage projects, replacement of diesel generators as they retire, and demand side management programs. The three new projects YEC is proposing are: electricity purchases from the planned Atlin Expansion Project, construction of a pumped storage facility at Moon Lake, and upgrading and expansion of the Southern Lakes Transmission Network. The combination of these three future potential projects not only stores and uses excess renewable power generated in the summer to decrease dependency on fossil fuels during the winter, but also makes connecting potential sources of First Nations-owned renewables in the Southern Lakes region more viable, and creates potential future electricity sales opportunities.

First Nations governments, development corporations and Citizens will have a key role in helping to shape and deliver this plan over the next 10 years. YEC recognizes First Nations as governments and potential energy proponents, partners and investors. In developing this plan, YEC will work pro-actively and collaboratively with First Nations governments and development corporations to forge partnerships and create opportunities for project ownership, investment, contracting, employment and training. First Nations will also be at the forefront of project assessments, permitting and approvals.

The cost of projects in this plan are estimated to be in excess of $500 million, one of the largest investments ever in the Yukon electricity system. Federal funding for the plan will be key to keeping the plan affordable and minimizing risks for Yukon customers.

The 10-Year Renewable Electricity Plan presents a generational opportunity for Yukon to invest in the critical renewable electricity projects needed to fuel Yukoners' lives, work and economy with clean energy. It creates opportunities for Yukon Energy, First Nations governments and development corporations, the Yukon and federal governments, and Yukoners to jointly shape the territory's electricity future.

A clean future lies ahead. Let's work together to meet Yukon's climate goals.

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Glossary of Key Terms

CAPACITY (DEMAND)	The supply (or consumption) of electrical power at a given instant in time. Usually measured in megawatts (MW) in long-term planning context.
DEMAND SIDE MANAGEMENT (DSM)	The attempt to reduce overall electrical consumption at customer sites via initiatives or implementation of codes/standards. Demand side management, if used during peak demand periods, can provide an alternative to supply-side dependable capacity additions.
DEPENDABLE CAPACITY	The maximum generation output that a resource can reliably provide in a specific time frame, expressed in megawatts (MW), typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. For thermal resources, dependable capacity was assumed to be equal to the installed capacity, since fossil fuels can be stored. For wind resources, dependable capacity is considered zero, as there is no guarantee that there will be the required wind speeds for the two consecutive weeks within the winter period.
DISPATCHABLE GENERATION	Refers to sources of electricity that can be dispatched at the request of power grid operators; that is, generating plants that can be turned on or off, or can adjust their power output on demand. Resource options such as thermal power plants and hydro power plants with reservoirs are dispatchable and they can meet changing electricity loads. In contrast, intermittent resources, such as wind are non-dispatchable because they can only generate electricity while their energy source is available.

ENERGY	The supply (or consumption) of electrical power over a period of time. Usually measured in kilowatt-hours (kWh) for residential usage or gigawatt-hours (GWh) for territorial usage. The annual energy supply must at least cover the annual energy consumption.
GENERATION RESOURCE	Refers to sources of energy that are converted to electrical power and provide energy and/or dependable capacity. Common generation resources include hydro, wind, solar, or thermal (e.g. natural gas or diesel).
INDEPENDENT POWER PRODUCER (IPP)	An energy producer who generates electricity for sale to utilities or consumers.
INSTALLED CAPACITY	The maximum amount of generating capacity that a generation resource is capable of providing, expressed in megawatts (MW).
LOAD	The electrical energy required to power homes, businesses and industrial processes. Sometimes referred to as demand.
N-1 (SINGLE CONTINGENCY) PLANNING CRITERION	A reliability planning criterion used to determine the capacity requirements of the system. YEC's N-1 criterion requires that each part of the YEC transmission grid should be able to carry the forecast peak winter demand, excluding major industrial demand, under the largest single contingency. The single largest contingency is defined as loss of the largest single element which could be either a transmission line or generating station. This criterion considers the ability to interrupt large industrial customers during an emergency event, which is why only non-industrial peak demand is included.
RENEWABLE ENERGY	Energy that comes from sources renewed on an ongoing basis through natural processes. Examples include sun (solar), wind, and flowing water (hydro).

1 Introduction

1.1 Yukon Energy Corporation

Yukon Energy Corporation (YEC) is a public electric utility owned by the Yukon Government through the Yukon Development Corporation (a Crown Corporation). YEC's mandate is to plan, generate, transmit and distribute a continuing and adequate supply of cost-effective, sustainable, clean and reliable electricity for customers in Yukon.

YEC owns and operates the Yukon's integrated transmission system, generating almost 100% of the electricity on this isolated, northern Canadian, electric grid. It is the electric utility with primary responsibility for planning and development of new generation and transmission facilities in Yukon. YEC is incorporated under the Business Corporations Act and regulated by the Public Utilities Act and the Yukon Waters Act.

1.2 Background: Drivers for a 10-Year Renewable Electricity Plan

In July 2019, YEC released its 5-year strategic plan with a bold 10-year vision to be a Canadian leader in sustainable energy by 2030. Later that year, based on the input of Yukoners, YEC's Board of Directors also decided not to move forward with the development of a new 20-megawatt thermal generation facility that would address Yukon's current and forecast capacity shortfall. This decision commenced the re-examination of potential renewable capacity resources.

In November 2019, Yukon government released a draft of its *Our Clean Future* strategy, with a vision for addressing climate change by building thriving, resilient communities powered by clean energy and supported by a sustainable green economy. In it, the government proposed that an average of 93% of electricity generated on the grid be produced from renewable sources and included specific actions to promote the electrification of the territory's transportation and heating sectors. These policy actions triggered the need for an update to YEC's long term load forecast.

These increased electricity requirements to enable a clean Yukon future and the Corporation's commitment to provide renewable capacity solutions to serve this demand formed the need to develop an updated plan for future renewable generation and transmission projects.

1.3 Yukon Integrated System

At present, the Yukon electrical system shown in Figure 1 comprises:

» One (1) large hydroelectric based grid called the Yukon Integrated System (YIS);

» One (1) medium-sized diesel-based grid serving Watson Lake; and

» Three (3) smaller isolated communities with diesel generation (Beaver Creek and Destruction Bay/ Burwash Landing) and solar/diesel generation (Old Crow).

Figure 1: Yukon Electrical Systems



1.4 YEC Resource Planning Criteria

Reliability means that electricity is available when customers demand it. Generation resources exist to supply electricity, and transmission resources exist to move electricity from generators to customers. Planning generation resources involves consideration of two primary supply aspects: energy and capacity. Energy is the total quantity of electricity produced over a period of time (e.g. a day or a year), while capacity is how much electricity can be produced at one time.

Being an islanded system, YEC must ensure there is always an adequate supply of both energy and capacity, including in the event of contingencies (i.e. loss of generation or transmission). Achieving these supply objectives is made more challenging by the islanded nature of the YIS, since YEC cannot rely on its neighbours to provide additional energy and capacity in times of need.

To address YEC's planning requirements, YEC used the following criteria in the resource planning process:

- **Energy Planning Criterion.** This criterion is defined as having firm energy equal to or greater than forecast future energy loads. The energy planning criterion must be met on an annual basis. It should be noted that although YEC plans for firm energy, YEC has excess firm energy available from thermal generation resources to meet the firm energy planning criterion over the planning period. As a result, the 10-Year Renewable Electricity Plan has been modeled on the basis of average energy for renewable generation resources which assumes average water, wind and solar irradiance.
- **Capacity Planning Criterion.** This criterion ensures that the system has sufficient capacity to meet peak demand (peak capacity) for two consecutive weeks under extreme cold winter conditions. The capacity planning criterion is based on the single contingency (N-1) criterion, which states that each part of the YEC transmission grid shall supply the forecast non-industrial peak winter demand, excluding major industrial demand, under the largest single contingency. Yukon's current largest single contingency corresponds to the loss of the 37 MW Aishihik Generation Station, either through an outage of the generating station itself or an outage of the L171 transmission line that interconnects the Aishihik Generating Station to the Takhini Substation.

Please refer to *Section 4.3: Resource Planning and Reliability Criteria* in the 2016 Integrated Resource Plan (IRP) for further details.

2 Context

2.1 Yukon Challenges

» **Islanded Grid.** Yukon cannot rely on adjacent Canadian provinces, territories or the State of Alaska to supply electricity, and must self-supply all its own capacity and energy.

» **Predominantly Hydroelectric Energy Generation.** Most Yukon electricity is generated using renewables, and as recently as 2016 more than 98% of Yukon's electric energy was supplied by renewable (primarily hydroelectric) generation, with the remaining 2% provided by thermal generation (diesel and natural gas fired generation). Hydroelectricity relies on the availability of water to generate electricity, and as a result YEC must anticipate and plan for potential drought conditions.

» **Mismatched Generation Supply and Electricity Demand.** Electricity demand in the Yukon is highly variable, and changes considerably over the course of each day and across seasons. Primarily driven by residential demand for services such as space heating, lighting, cooking and appliance loads, Yukon's electricity demand typically peaks during cold winter days during and shortly after dinner time (typically between 4pm and 6pm). There is a seasonal mismatch between the timing of maximum available electricity production from hydroelectric generation (which peaks in the summer months) and maximum customer demand (which peaks in the winter months). As a result, YEC regularly relies on thermal generation to fill the gap between available hydroelectric generation and electricity demand during the winter peak periods.

» **Industrial Load Changes & Ratepayer Protections.** Yukon's small customer base means that the addition or loss of a major industrial load (e.g. a mine) on the grid has a substantial effect on both overall electricity demand and the total electricity sales volumes. This impacts how YEC's costs are divided amongst ratepayers. This volatility in industrial customer demand makes it challenging for YEC to forecast its future generation supply requirements, or to mitigate potential step changes in electricity rates which can occur with the loss of industrial customer demand.

2.2 Federal Funding to Enable Renewable Capacity

YEC is subject to price regulation and may only charge electricity prices approved by the Yukon Utilities Board (YUB). Since the YUB is an economic regulator, this implies that YEC must select the lowest cost resource options to meet future demand, while still meeting applicable regulations and laws.

Planning for future capacity resource investments is a key outcome of the 2016 Integrated Resource Plan and this current plan. Since thermal generation resources typically offer the lowest cost source of new capacity, this typically leads to the inclusion of new thermal facility investments. For example, a new 20 MW diesel plant was included in the recommended portfolio of the 2016 Integrated Resource Plan.

YEC's 2016 Resource Plan involved a "blank sheet" planning process that evaluated all generation options available to YEC without being constrained or influenced by planning pre-conditions. The 10-Year Renewable Electricity Plan, however, is focused on prioritizing renewable electricity solutions, which strongly influenced the generation resource options that were considered.

Accordingly, in order to meet the objectives of the 5 Year Strategic Plan and the policy objectives set out in the Yukon government's *Our Clean Future* strategy, Federal funding was assumed to support the development of renewable capacity sources that would otherwise not be selected as the lowest cost capacity resources. Federal funding also serves to reduce the impact of large infrastructure development on Yukon electrical rates, thus keeping residential and industrial rates affordable. This will allow Yukon to maintain an affordable quality of life, and ensure Yukon remains a competitive jurisdiction for future industrial development.

In Yukon, there is a long history of the Federal government funding support for large electrical infrastructure development (e.g. Carmacks-Stewart Transmission Project, Mayo B, etc.) to protect ratepayers and keep rates affordable. For the purposes of this plan, it is assumed that new generation and transmission projects will receive Federal funding, to a typical maximum of 75% of total capital cost.

2.3 Relevant Government Policy and Initiatives

YEC is accountable for meeting policy directives issued by the Yukon government and its agencies. Key recent policy developments include:

1) Micro-Generation Policy

2) Independent Power Producer Policy

3) Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

2.3.1 Micro-Generation Policy

Issued by the Yukon government in October 2013, this policy aims to encourage the small-scale generation of electricity by individuals, small businesses and communities to meet their own needs, as alternatives or supplements to centralized grid-connected power. The policy is applicable to micro-generation projects up to 50 kW. YEC has included micro-generation-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.2 Independent Power Producer (IPP) Policy

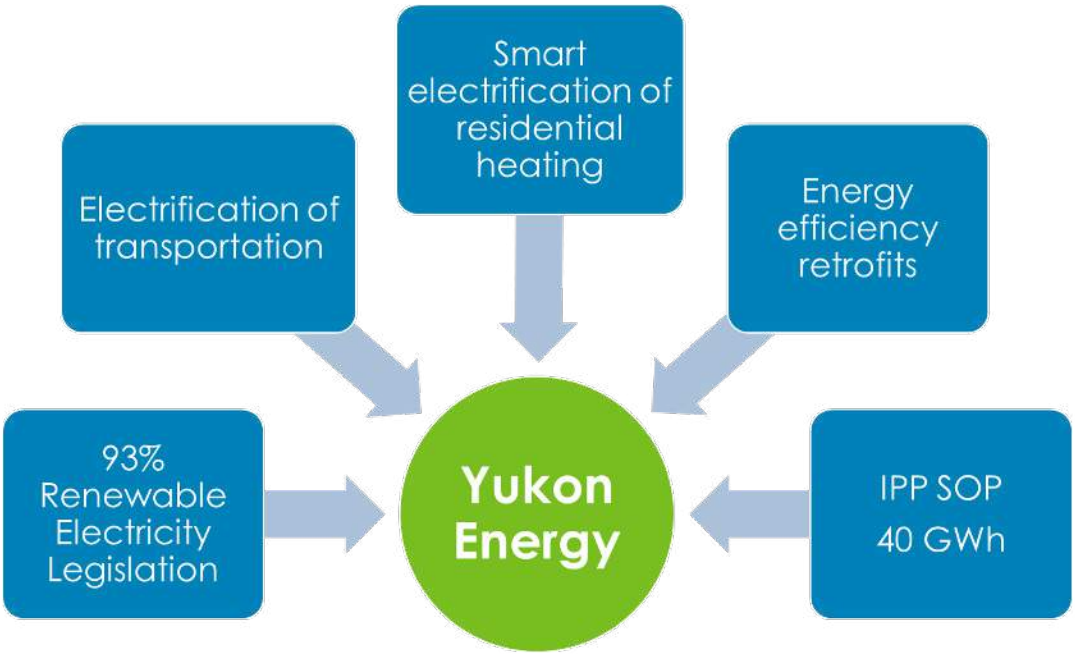
Issued by the Yukon government in October 2015, the IPP policy aims to provide opportunities for non-utility entities to develop new generation resources that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy.

YEC and ATCO are actively working with the government to structure a Standing Offer Program (SOP), which is a key element of the IPP Policy. The SOP is intended to provide a standardized technical and commercial framework to facilitate grid connection of new small capacity generation (in the 30 – 2,000 kW range). YEC included 40 GWh of annual IPP-sourced energy in its committed resource assumptions for future supply options in the 10-Year Renewable Electricity Plan.

2.3.3 Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy

Yukon government released a draft of its *Our Clean Future* strategy for public review in November, 2019. The strategy was formally launched in September, 2020. Key goals of the strategy include reducing greenhouse gas emissions, ensuring Yukoners have access to reliable, affordable and renewable energy, adapting to the impacts of climate change, and building a green economy. Figure 2 provides an overview of the various elements of the Yukon government strategy which influenced YEC's expected load and generation requirements.

Figure 2: *Our Clean Future* Strategy Influence on YEC 10-Year Renewable Electricity Plan



The *Our Clean Future* strategy states that Yukon government will develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average, while aiming for an aspirational target of 97% renewable electricity by 2030. This minimum requirement, and the long-term aspirational target, impacted the generation requirements used in the development of the 10-Year Renewable Electricity Plan.

The electrification of transportation and smart heating called for by the strategy is expected to increase the amount of electricity required by Yukoners, while energy efficiency retrofits may reduce or change electricity requirements for some entities. The impact of these actions was reflected in the load forecasts developed for this Plan. The changes to the IPP Standing Offer Program, and the support of Demand Side Management (DSM) programming, were also reflected in the energy portfolio modeling.

The *Our Clean Future* strategy is focused on six priorities: Transportation; Homes and Buildings; Energy Production; Communities; Innovation; and Leadership. Within these priorities, a number of strategies and related actions for energy conservation and the development of renewable energy resources were identified. Table 1 summarizes the key electricity-related initiatives relevant to YEC which were accounted for in the development of the 10-Year Renewable Electricity Plan.

Table 1: Government Energy & Climate Change Strategy: Electricity-Related Initiatives for YEC

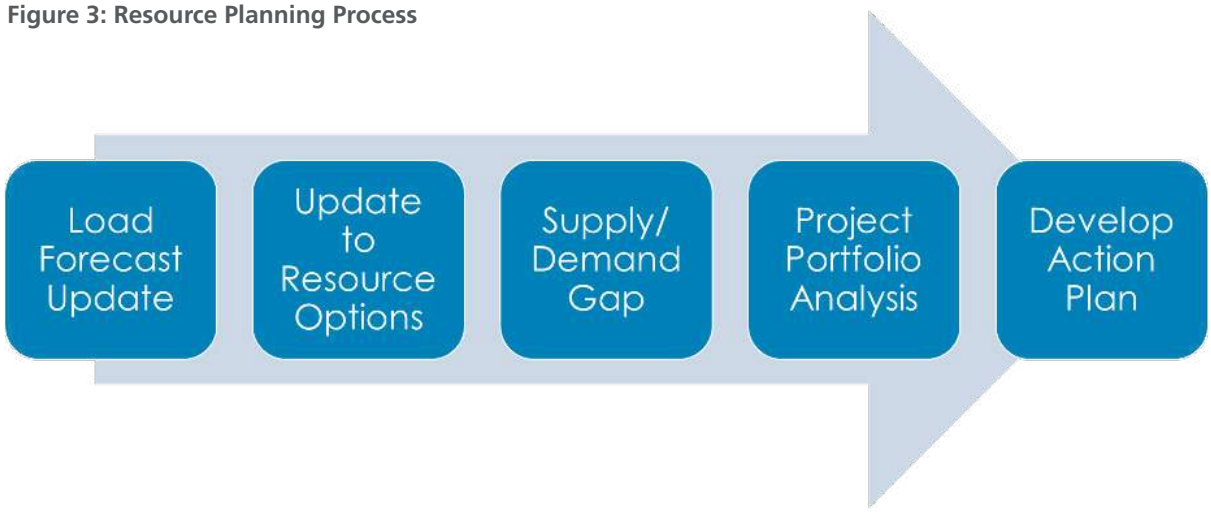
PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Transportation	Actions #T1, #T2, #T4, and #T6	Increase the availability and use of zero emission vehicles, install fast-charging stations across Yukon, and require new residential buildings in greater Whitehorse area to support Level 2 electric vehicle charging.	4,800 EVs by 2030	Yes (included 5,000 EVs by 2030, based on November 2019 Draft Strategy).
Homes and Buildings	Action #H18, #H21, #H22	Replace residential fossil fuel heating systems with smart electric heating systems.	1,300 buildings over 10 years	Yes
Homes and Buildings	Action #H26, #H27, #H28	Allow Yukon's public utilities to partner with Government of Yukon to pursue cost-effective demand-side-management measures, and collaborate on delivery of capacity and energy DSM programs.	No specific target.	Yes

PRIORITY	ACTION NUMBER	ELECTRICITY RELATED INITIATIVE	TARGET	ACCOUNTED FOR IN 10-YEAR RENEWABLE PLAN?
Energy Production	Action #E7, #E8, #E10	Continue to implement the IPP Policy and the Micro-generation Program and increase the SOP limit to support additional community-based renewable energy projects.	Increase the SOP limit from 20 GWh to 40 GWh, 7 MW of installed Micro-generation capacity by 2030	Yes
Energy Production	Action #E1	While aiming for an aspirational target of 97% by 2030, develop legislation by 2023 that will require at least 93% of the electricity generated on the Yukon Integrated System to come from renewable sources, calculated as a long-term rolling average.	93% long-term rolling average	Yes
Energy Production	Action #E12	Conduct research into the potential to use geothermal energy in Yukon for heating and/or electricity.	No specific target.	No

3 Resource Planning Methodology

The goal of the resource planning process is to develop recommended actions for meeting Yukon's energy and capacity electricity demand requirements over the 10-year horizon.

Figure 3: Resource Planning Process



The planning process was built on the 2016 Resource Plan and followed these steps:

1. **Load Forecast Update**. Forecast future electricity demand for both energy and peak capacity (Section 4);
2. **Supply/Demand Gap.** Create an inventory of existing, committed and planned generation resources (Section 5), then determine potential shortfalls between future demand and generation supply resources in terms of both energy and capacity (Section 6);
3. **Update to Resource Options.** Create an inventory of future potential generation resource options (Section 7);
4. **Project Portfolio Analysis.** Analyze and develop a portfolio of options to address the energy and capacity shortfalls (Section 8); and
5. **Action Plan**. Develop a recommended action plan (Section 9).

It should also be noted that although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the resource planning process was completed based on a longer timeframe (i.e. 2020 to 2035) to allow for the phased development of certain resource options included in the portfolio analysis. Each step of the planning process is described further in the following sections.

4 Load Forecast

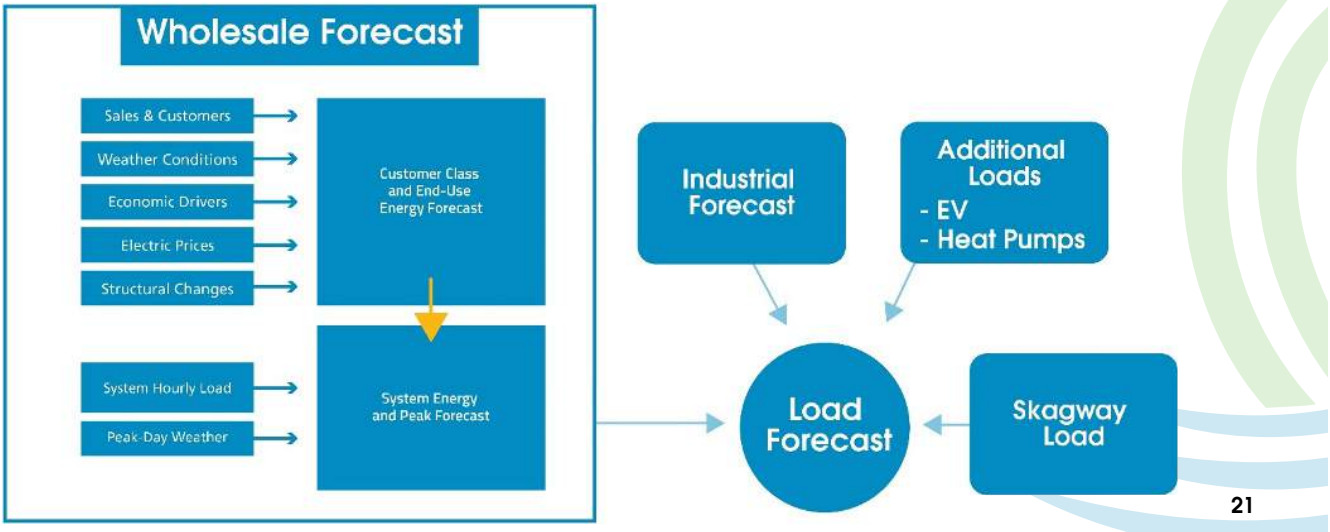
4.1 Load Forecasting Overview

The energy and peak capacity demand forecast estimates YEC's electricity needs over the planning horizon. The forecasting process used multiple inputs provided by external expert sources and inputs from the Yukon government, as well as production forecasts for major industrial customers.

Energy and peak capacity demand forecasts were developed in two parts:

1. **Part 1.** The energy and peak capacity demand forecasts from the 2016 Integrated Resource Plan were updated by Itron using their SAE MetrixND econometric model. The updated forecasts capture a range of input data, including historical sales and energy data by customer class, economic activity, population projections, average expected weather conditions, electricity prices, and improvements in end-use efficiency and standards. The economic activity input assumptions were based on the Yukon government economic model. This included an industrial activity forecast, reflection of the state of the economy in 2019 based on actual population and household numbers, and updated Gross Domestic Product (GDP) statistics.
2. **Part 2.** Additional loads not captured in Part 1 of the demand forecasts were added separately to the demand forecast output. These additional loads included industrial grid-connected mining loads, incremental loads from specific climate policy incentives such as the adoption of electric vehicles and the electrification of space heating in buildings, and the incremental load associated with the potential electrification of cruise ships in Skagway.

Figure 4: Load Forecast - Process Overview



4.2 Load Forecast Scenarios

Yukon's small customer base means that the addition or loss of a major industrial mining load on the grid has a material impact on overall energy requirements. In order to recognize and quantify this volatility, scenarios describing credible potential alternative futures were developed by making specific assumptions concerning the future loads of existing grid-connected mines. Other factors, such as increased loads from the electrification of cruise ships in Skagway and future energy policy actions, were also incorporated into the scenarios.

There are a number of prospective mining projects located far from the Yukon grid (e.g., Coffee Gold Project, BMC Minerals Kudz Ze Kayah project) that could be developed during the planning period. However, since these projects are assumed to be off-grid operations with no direct impact to on-grid electricity demand, and there is limited visibility on the probability or timing of these projects, they were not considered as part of this analysis. The scenarios also did not consider any new large on-grid mining projects being developed in the 10-year planning period as there is limited visibility on the certainty of any of these potential projects coming to fruition. Should new mining developments emerge, future long-term resource plan updates would contemplate how to address the resulting load impact.

The four (4) scenarios considered were:

1. Low Case;
2. Base Case (without Skagway);
3. Base Case (with Skagway); and
4. High Case.

The third scenario in the list, Base Case (with Skagway), represents the expected Base Case for the YEC load forecast, and is referenced as the "Base Case" throughout the remainder of this report. Note that this analysis was conducted prior to the COVID-19 pandemic. YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

Table 2: Load Forecast Scenarios - Assumptions

	LOW CASE	BASE CASE (WITHOUT SKAGWAY)	BASE CASE	HIGH CASE
Wholesale Forecast	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions	YG Economic Model Energy Policy Actions
Eagle Gold Load	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2029 2019 updated forecast	Operation to 2035 2018 load forecast
Minto Load	None	3 MW average to 2022	3 MW average to 2022	3 MW average to 2031
Alexco Load	None	2.5 MW average to 2035	2.5 MW average to 2035	2.5 MW average to 2035
EV Load	2,000 EVs by 2030; L2 charging; no Time of Use (TOU) rates	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU	6,000 EVs by 2030; L2 charging; no TOU
Skagway Load	None	None	35 GWh/yr summer demand from 2026 to 2035	35 GWh/yr summer demand from 2026 to 2035

4.3 Energy Forecasts

This energy forecast for the Yukon Integrated System (YIS) (see Section 1.3) is for the Base Case scenario. Energy refers to the quantity of electricity, expressed in gigawatt-hours (GWh) that is sold over a specified period of time.

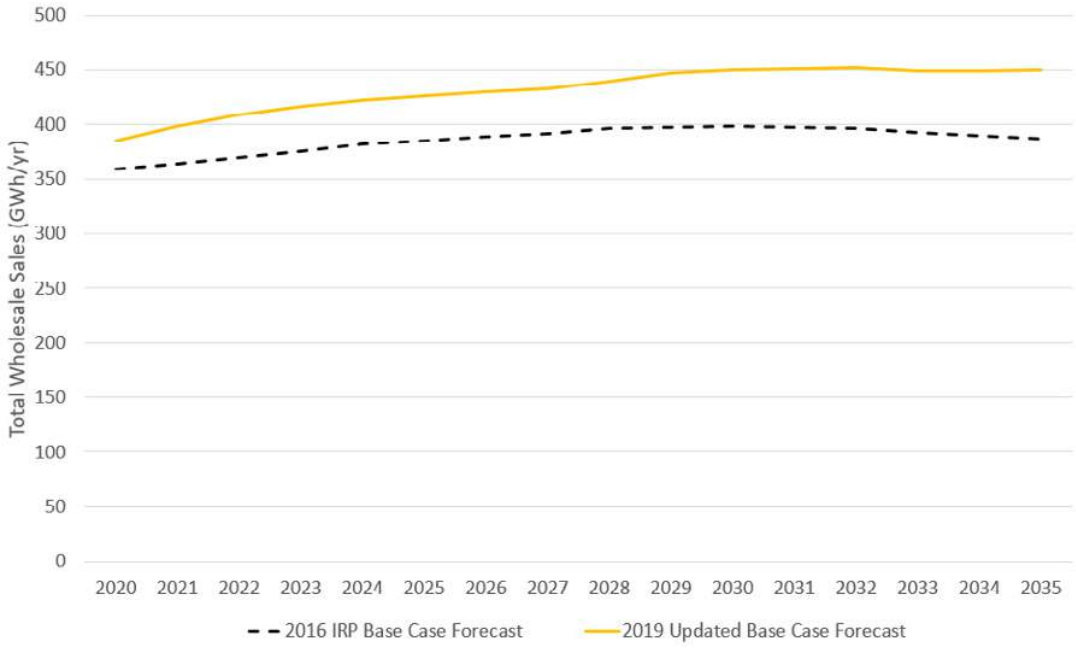
The YIS energy forecast comprises two major elements, wholesale load and industrial (i.e. mining) load, which are combined to produce the total energy forecast. To show how the load forecasts have changed over time, the previous forecast values from the 2016 IRP are included in each of the following graphs.



4.3.1 Annual Energy Forecast

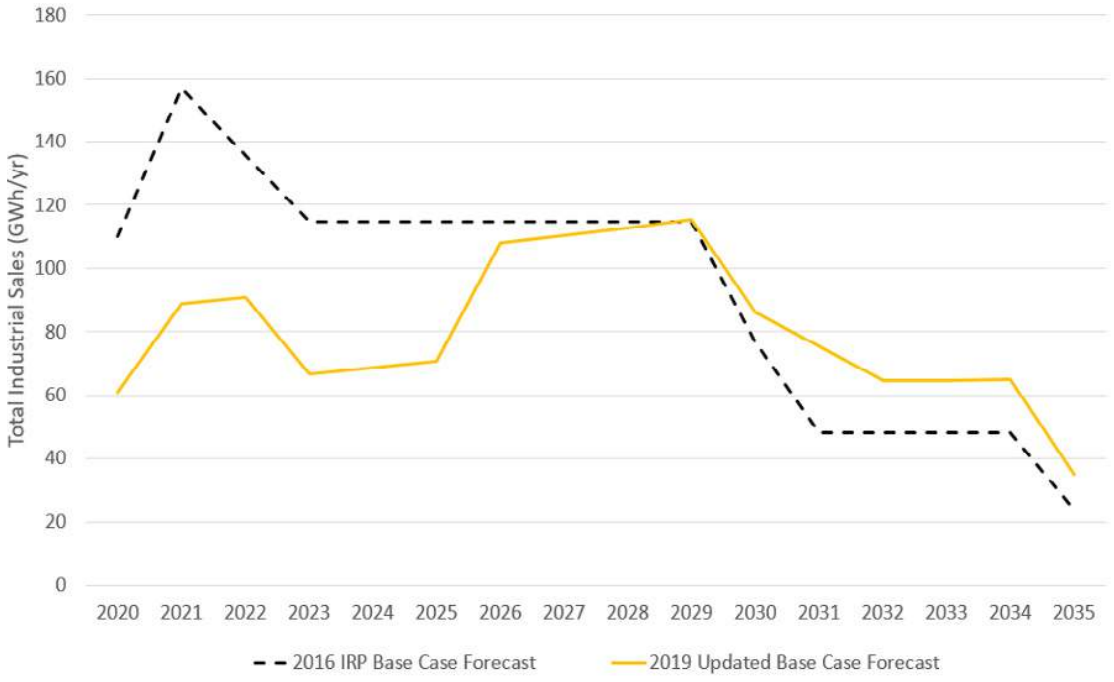
The annual wholesale energy forecast, which includes the incremental Yukon Energy Policy Action loads for the Base Case scenario relative to the 2016 IRP Base Case forecast, is shown in Figure 5. The updated 2019 energy forecast is higher than the 2016 forecast for the entire planning period, including the initial 2020 year. Energy load is higher in 2020 due to higher than forecast economic and population growth over the 2016-2019 period. In addition, the data in Figure 5 illustrates that energy demand is forecast to grow at a higher rate than forecast in the 2016 IRP due to impacts of Yukon government electrification policy actions which include electric vehicles and electrification of space heating.

Figure 5: Base Case - Wholesale Forecast Relative to 2016 IRP Base Case Forecast



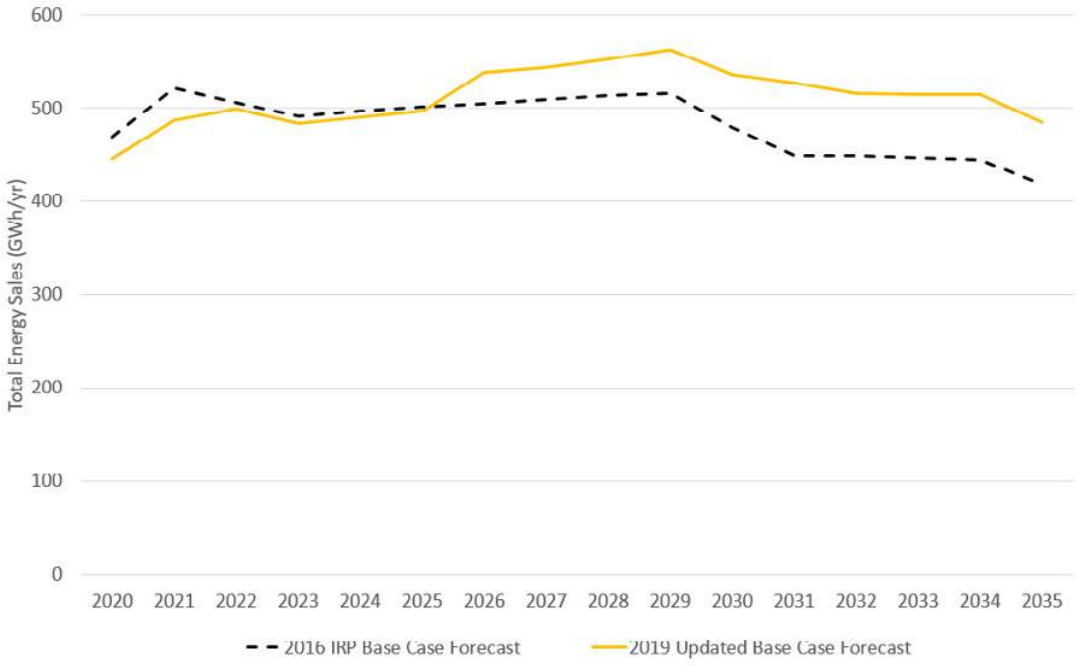
The annual industrial forecast for the Base Case scenario relative to the 2016 IRP Base Case forecast is shown in Figure 6. It should be noted that the 2019 industrial forecast also includes an additional 35 GWh/year load from year 2026 onwards for the assumed electrification of cruise ships in Skagway under this scenario. The observed decrease in forecast industrial load at the start of the planning period (2020-2025) relative to the 2016 forecast is primarily driven by a reduction in the forecast Victoria Gold mining load. The observed increase in forecast industrial load from year 2026 onwards is due to the additional load associated with the electrification of cruise ships in Skagway. Finally, the observed drop-off in industrial load from year 2029 onwards is due to the assumed shut-down of the Eagle Gold mine.

Figure 6: Base Case - Industrial + Skagway Forecast Relative to 2016 IRP Base Case Forecast



The total energy forecast (i.e. wholesale + industrial + Skagway) for the Base Case scenario relative to the 2016 IRP Base Case scenario is shown in Figure 7. The forecast increase in wholesale load is partially offset by the reduction in mining load at the beginning of the planning period, but an increase in total energy is observed from year 2026 onwards due to the addition of the Skagway load. As a result, the updated total energy forecast for the Base Case scenario remains very similar to the 2016 forecast, with slightly lower energy demand in the near-term years, and higher energy demand in the latter years of the planning period.

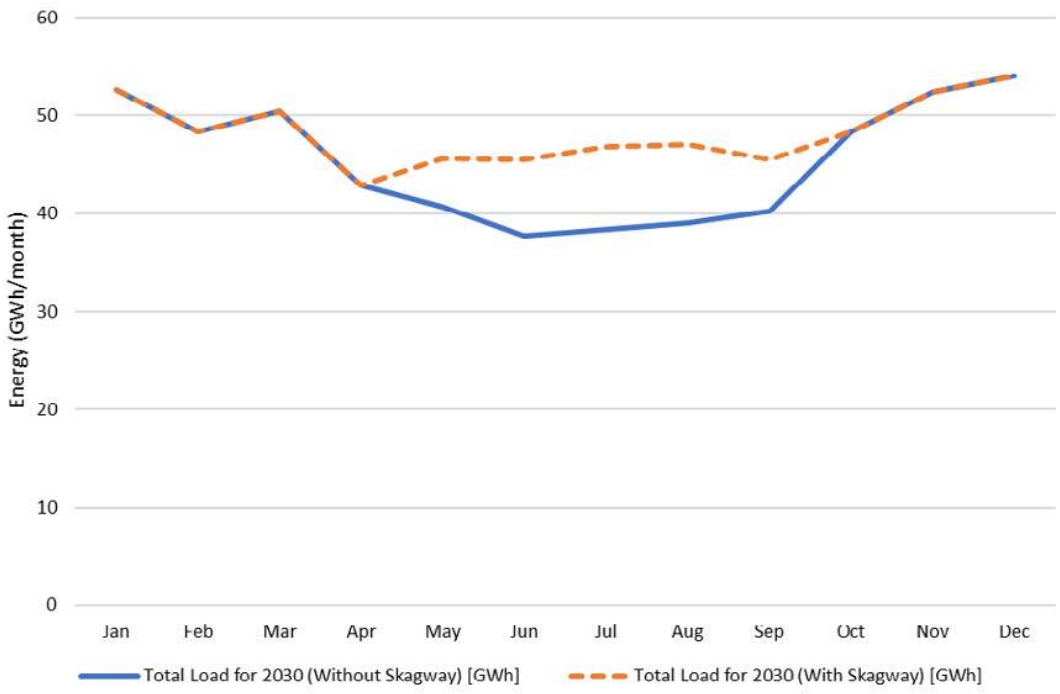
Figure 7: Base Case – Total Energy Forecast Relative to 2016 IRP Base Case Forecast



4.3.2 Seasonal Profiles

Seasonal energy profiles help demonstrate how energy demand changes over the course of a year and identifies which months have the highest and lowest energy demand. Figure 8 shows forecast monthly energy profiles for the year 2030 (with and without Skagway load). The figure does not account for any potential summer "load" from a pumped storage resource (e.g. energy consumption to pump water into the upper storage reservoir). Although the shape of the monthly energy profile will vary over the planning period, the YIS will remain a winter peaking system with maximum energy demand occurring in the winter months and lower energy demand in the summer months. Electricity policy changes in Yukon are not expected to change the fundamental challenge of meeting Yukon's increased energy demand in the winter months.

Figure 8: Monthly Demand Shape for 2030 (With & Without Skagway Load)



4.4 Peak Capacity Demand Forecast

Peak capacity demand is the maximum instantaneous quantity of electricity that customers require (and YEC must supply), expressed in megawatts (MW). For forecasting and planning analyses, which are conducted using the single-contingency (N-1) planning criterion, industrial demand is excluded from the peak capacity demand as it is assumed during an emergency event industrial customers could be interrupted.

A new peak capacity demand record of 103.84 MW (97.6 MW non-industrial peak) was set on January 14, 2020. The previous record peak was 92.99 MW (90.5 MW non-industrial peak). As a result of this record-breaking peak, YEC was required to update its non-industrial peak capacity demand forecasting model to account for updated information on the actual peak demand of the Yukon system during prolonged cold weather events.

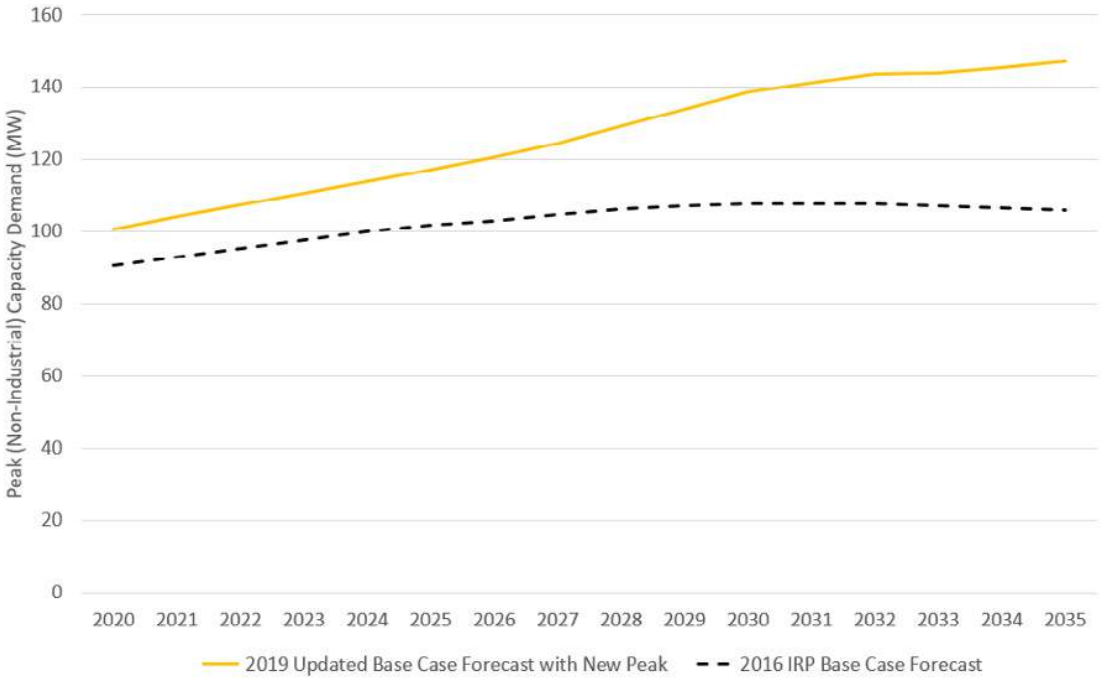
It should be noted that including Skagway in the Base Case does not impact the non-industrial peak capacity demand forecast. Skagway is assumed to add approximately 35 GWh of summer energy per year from year 2026 onwards, but it does not impact the peak capacity demand which occurs in the winter.

The updated non-industrial peak demand for the YIS relative to the 2016 IRP Base Case scenario is shown in Figure 9. The significant growth in the peak non-industrial demand forecast relative to the 2016 IRP Base Case forecast was primarily driven by:

» increased wholesale demand (e.g. population growth) and

» government policy actions related to electrification (e.g. electric heating, electric heat pumps and the adoption of electric vehicles).

Figure 9: Base Case – Updated Peak (Non-Industrial) Capacity Demand Forecast vs. 2016 IRP



5 Update to Resource Options

Generation resources considered as part of the 10-Year Renewable Electricity Plan are described in terms of their average energy and dependable capacity, where:

» **Average Energy**, expressed in GWh/year, is the total quantity of energy that the resource option produces in an average year. An average year is defined as having historically average fuel availability, such as water, wind, or solar irradiance. The fuel supply for a thermal generation station (i.e. diesel or natural gas) is available with a high degree of certainty. Because these fuels can be reliably stored, they are assumed to have 100% fuel availability.

» **Dependable Capacity**, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on fuel availability. For hydroelectric generation this means the average of water inflows for the five driest years in the hydrological record. For thermal resources, dependable capacity is equal to the installed capacity, since fossil fuels can be reliably stored. For wind and solar resources, dependable capacity is considered zero, since there is no guarantee that there will be available fuel (e.g. sun or wind) for the two consecutive weeks within the winter period.

The four (4) categories of generation resources considered as part of the 10-Year Renewable Electricity Plan, and described further in the following sub-sections, are:

1. Existing Resources;
2. Committed Resources;
3. Planned Resources; and
4. Future Potential Resources.

5.1 Generation Resources by Type

5.1.1 Existing Resources

These include YEC's legacy hydroelectric and thermal (diesel-fired and natural gas-fired) generation resources. The thermal diesel-fired resources owned and operated by ATCO in the communities connected to the Yukon Integrated System are also included in the category of Existing Resources. ATCO's generation resources are assumed to contribute to the dependable capacity of the system, with the underlying expectation that ATCO will provide backup power whenever needed.

The retirement of diesel generators that reach end of life over the planning period were also included in this category. Over the planning period, YEC anticipates the retirement of the sole remaining Mirrlees diesel engine in Faro (FD1) and two diesel engines from the Dawson Diesel Plant (DD2 and DD5) in 2023.

The inventory of the existing and retiring YEC and ATCO resources and their technical attributes are presented in Appendix A:.

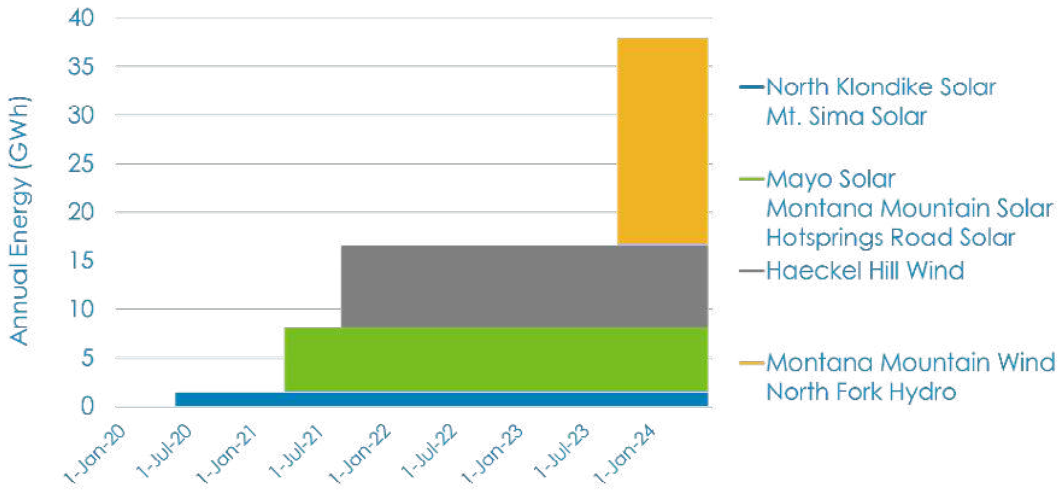
5.1.2 Committed Resources

These include generation resources that have secured YEC Board approvals and for which YEC is in the process of planning and/or constructing. That is, there is no turning back on the commitment to building these generation resources. YEC considers the following as committed resources:

1. **Whitehorse Hydro #2 (WH2) Uprate Project.** The Whitehorse Hydro WH2 Uprate Project will increase the efficiency and maximum capacity of the WH2 generation unit, resulting in more generated electricity for the same water throughput. The WH2 Uprate Project at the Whitehorse generating station will provide 6.2 GWh of annual energy and at least 0.64 MW of dependable capacity.
2. **Battery Storage System.** On September 5, 2019, the Government of Canada committed $16.5 million towards the construction of a new battery storage system in Yukon. The new battery, which is currently projected to be sized at 8 MW/ 40 MWh, will help meet growing peak demands for power while displacing diesel and improving grid reliability.

3. **Standing Offer Program (SOP).** The SOP is outlined in the Independent Power Production (IPP) Policy of the Yukon territorial government issued in 2015. The SOP included in the 10-Year Renewable Electricity Plan envisions 40 GWh/year of energy delivered by the IPP sector by the year 2024 and continuing past the end of the planning period. Figure 10 illustrates the current forecast of the projects anticipated to participate in the program and the resulting expected profile of renewable energy contribution growth from the SOP between 2020 and 2024. Since it is assumed that the SOP projects will most likely be intermittent renewable resources such as wind and solar, no dependable capacity is assigned to these resources.

Figure 10: IPP Standing Offer Program Anticipated Projects



4. **Micro-Generation Program.** The Micro-Generation policy issued by the Yukon government in October 2013 outlines this program. The policy is applicable to projects up to 50 kW. The micro-generation included in the 10-Year Renewable Electricity Plan envisions 6.5 GWh/year of delivered energy by the year 2024 and continuing past the planning period. Similar to the SOP, no dependable capacity is assigned to micro-generation projects because they will be comprised of intermittent renewable resources such as wind and solar.

5.1.3 Planned Resources

These include generation resources which have reached advanced planning stages but have yet to secure all necessary YEC Board approvals. YEC considers the following projects to be Planned Resources:

1. **Whitehorse Unit #4 (WH4) Uprate Project.** This project will increase the maximum water flow at WH4, resulting in an increased maximum output. The WH4 Uprate Project at the Whitehorse generating station will provide 0.9 GWh of annual additional energy. Although this project increases the maximum capacity of the unit, it does not provide additional dependable capacity. This is because water flow in the winter is limited by downstream Yukon River system ice flow restrictions. Subsequent to the completion of this report, the YEC Board of Directors approved the WH4 Uprate Project to proceed in May 2020.

2. **Southern Lakes Enhanced Storage Project (SLESP).** The SLESP will expand the storage range on the Southern Lakes system, which provides water (i.e. fuel) storage for the Whitehorse generating station. This will be achieved by decreasing the licensed Low Supply Level by up to 10 cm and increasing the licensed Full Supply Level by up to 30 cm. Although the SLESP is a water storage project that does not generate electricity itself, it will enable generation of an additional 6.5 GWh of electricity each year at the Whitehorse Hydro facility.

3. **Mayo Lakes Enhanced Storage Project (MLESP).** This project seeks to enhance water storage at Mayo Lake by lowering its current licensed minimum level by up to one metre. The MLESP would generate an additional 4 GWh of electricity each year.

4. **Diesel Replacement.** By replacing retired diesel generator units at existing generation facilities, YEC can reduce the need for rental diesel generators from November through March. The total replacement diesel assumed over the planning period amounts to 12.5 MW.

5. **Demand Side Management (DSM).** DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. In 2014, YEC and ATCO Electric Yukon jointly launched and operated a DSM program called inCharge which provided rebates and electricity savings kits. However, the YUB denied the costs of this program in its decision on YEC's 2017-2018 General Rate Application. As a result, YEC's DSM activities are on hold pending confirmation that future DSM costs will be allowed. The focus of a relaunched DSM program would be on measures that deliver peak capacity savings (i.e. reductions in peak electricity consumption). A suite of programs has been developed which will be implemented once there is regulatory certainty about allowing of future DSM-related costs. The DSM programming is forecast to provide up to 6.7 GWh of annual energy and 7 MW of dependable capacity by 2030.

For the purposes of this report, it was assumed that Planned Resources will be constructed and operational as planned, and therefore are treated similarly to Committed Resources.

5.1.4 Future Potential Resources

These are potential generation resource options available to meet the needs of YEC's customers over the next 10 years that have not yet advanced into development. These generation resources are described in Section 7.

5.2 Summary: Existing, Committed and Planned Generation Resource Forecast

In Figure 11 and Figure 12, the Existing Resources are shown as blue bars and the Committed and Planned Resources are shown in darker and lighter shades of grey, respectively.

Figure 11: Energy Forecast from Existing, Committed and Planned Resources

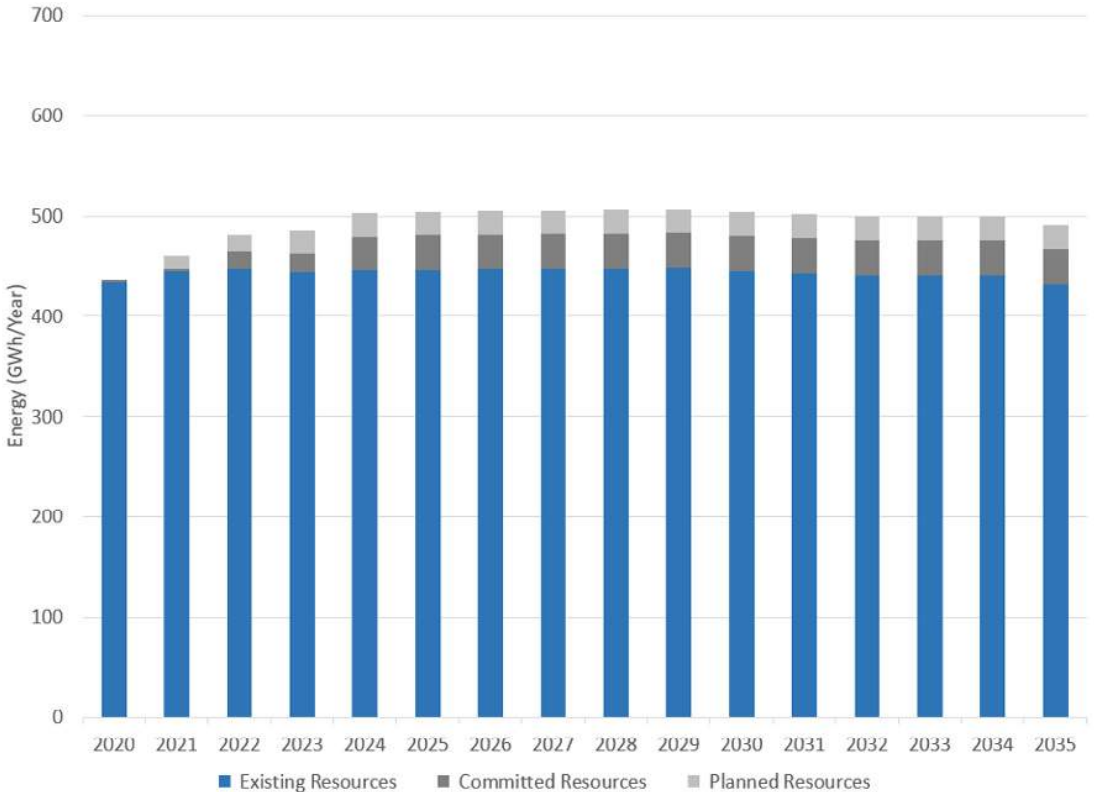
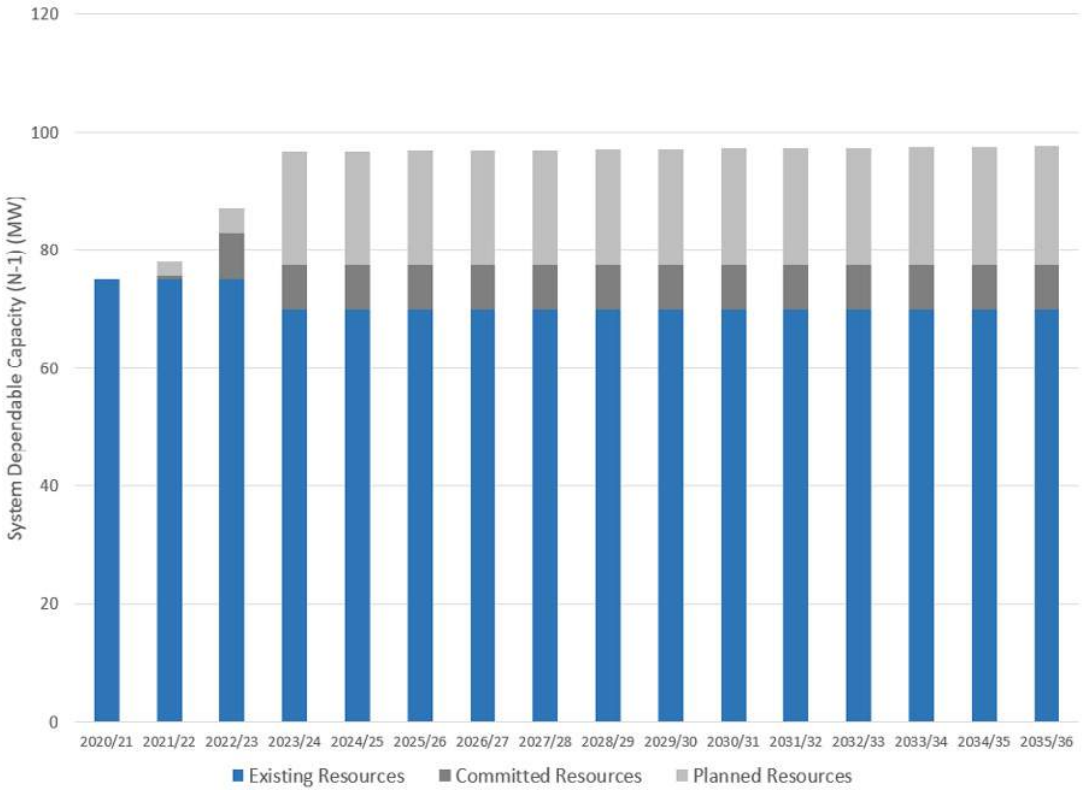


Figure 12: Dependable Capacity (N-1) from Existing, Committed and Planned Resources



6 Supply & Demand Gap

6.1 Methodology

The goal of the resource planning process was to develop recommended actions for YEC to both meet YIS's electrical energy needs and satisfy the capacity gaps over the 10-year horizon. The difference between electrical demand and generation supply is the gap, or "Need", as shown in Figure 13.

Figure 13: Gap Analysis Overview



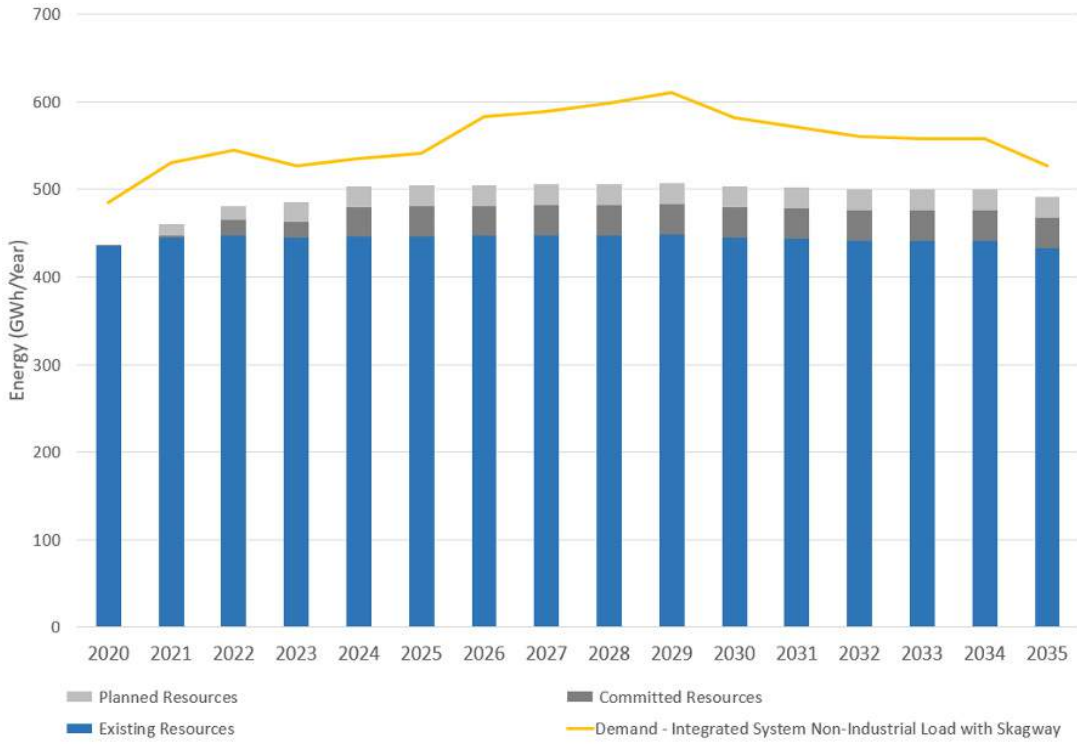
This gap analysis calculates the difference between the forecast energy and peak capacity demand and the expected future resource capability (including Existing, Committed and Planned Resources). The analysis is for the expected Base Case for the 10-Year Renewable Electricity planning evaluations.

6.2 Energy Gap Analysis

6.2.1 Annual Energy Gap

Figure 14 shows the gap between forecast annual energy demand (from Figure 7 in Section 4) and forecast generation (from Figure 11 in Section 5). A detailed breakdown, including individual resources, is included in Appendix A. The annual energy gap increases from 49 GWh in 2020 to 100 GWh in 2029.

Figure 14: Annual Energy Gap Analysis (Base Case)



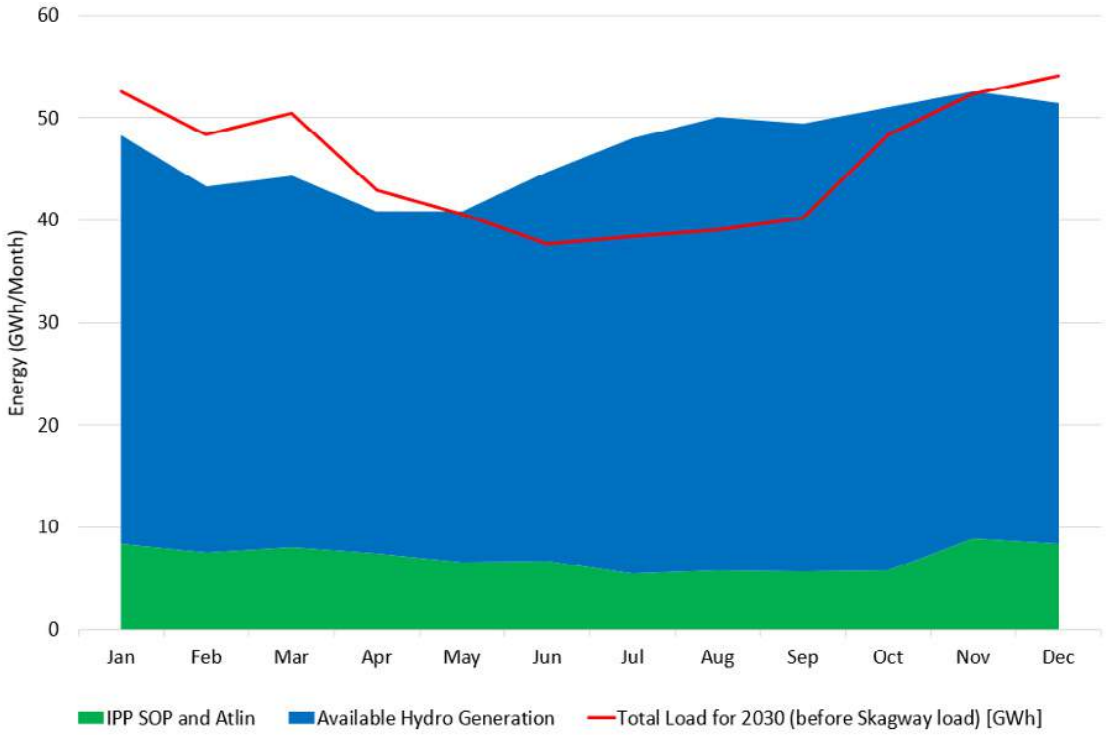
The energy gap between YEC's future expected resource capability and forecast load under average water conditions (as illustrated in Figure 14) implies that in some years YEC will need to utilize thermal resources if it does not develop any new renewable resources. In those years of average or below average water, YEC will need to run LNG, and potentially some diesel, to meet Yukon's energy needs.

This energy gap creates an opportunity for YEC to develop new renewable generation resources. These have the potential reduce reliance on thermal resources (LNG and diesel) to meet the forecast energy gap needs, particularly in low water years. It will be necessary to develop these new renewable energy resources if YEC is to meet the target specified in Yukon government's *Our Clean Future* strategy (a 93% rolling average in renewable energy).

6.2.2 Monthly Energy Gap & Summer Spilled Energy

Figure 15 shows the forecast monthly energy demand compared to the supply of hydroelectric and IPP SOP renewable energy supply for the year 2030.

Figure 15: Monthly Renewable Supply vs Demand (2030)



This figure illustrates that YEC will have surplus energy available during the summer but insufficient energy available during winter months to meet forecast energy demand. Additional data on the monthly and annual energy gap is provided in Appendix B.

Perhaps the most important conclusion to be drawn from Figure 15 is that Yukon is forecast to have surplus energy available in the summer months that will be permanently lost. Typically, this will be in the form of water spilled over the dam at the Whitehorse generating facility. Because other renewables such as solar and wind sourced from IPPs are not dispatchable, their energy must be accepted by YEC. YEC must then use its dispatchable hydroelectric assets (i.e. Whitehorse hydro during the summer) to balance supply and demand. Therefore, YEC will be forced to spill water over the Whitehorse dam whenever excess generation is supplied into the YIS. This seasonal mismatch between potential electricity production from hydro generation and the timing of maximum customer demand is a key planning constraint for YEC.

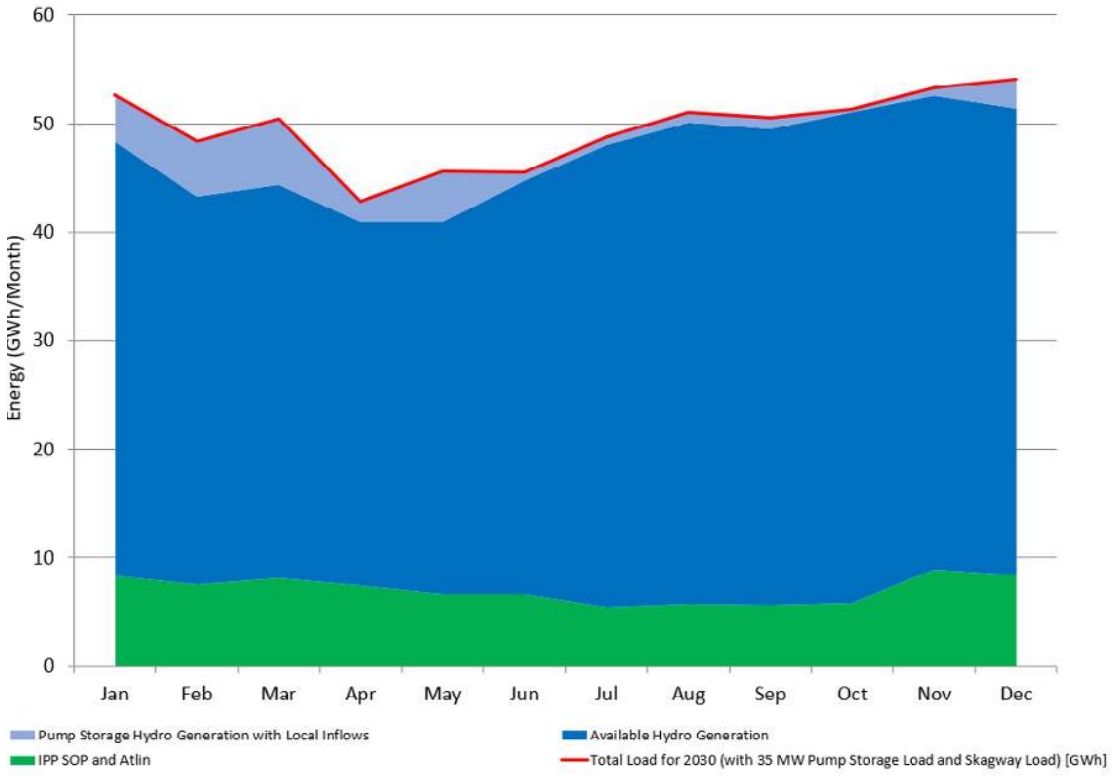
Two development options that would help address this issue are considered in this plan:

1. **Development of Seasonal Storage.** Since YEC has surplus energy available in the summer months and a deficit in winter months, there is a potential to use seasonal storage to store excess summer energy. That is, water spilled at YEC's existing hydro facilities could be stored and used for generation during the winter to meet winter loads. The only commercially available renewable technology for long term fuel storage in the quantities required by YEC (i.e. 40+ GWh) is pumped storage hydro.
2. **Securing New Customers for Summer Energy.** Another option to reduce summertime spilled water (i.e. wasted energy) is to secure new customers looking to purchase summer energy. By developing and investing in the Southern Lakes area as part of the 10-Year Renewable Electricity Plan, YEC has the potential opportunity to sell surplus summer energy to Skagway for the provision of clean shore-side power to cruise ships. The Skagway pier can interconnect up to four (4) cruise ships at once, which can amount to approximately 35 GWh/year of summer energy demand. Currently, cruise ships visiting Skagway in the summer burn diesel to generate shipboard electricity while at port. The electrification of shore-side power is one of the leading strategies that cruise ship operators employ to reduce their greenhouse gas (GHG) emissions while at port. This is an opportunity to utilize YEC's otherwise spilled water (i.e. wasted energy) to increase revenues to offset Yukon electricity costs, while also reducing GHG emissions in Skagway.

By capturing the surplus energy from otherwise spilled water through a combination of seasonal storage development and new summer energy customers, monthly energy supply and demand will be better matched.

This is illustrated in Figure 16 where the increased summer energy demand would reduce the excess amount of hydro generation in the summer months, as demonstrated previously in Figure 8. Additionally, summer demand would be further increased by the pumped storage facility utilizing energy to pump water from the lower reservoir into the upper reservoir. The excess hydro generation would then be available for use in the winter months due to this seasonal storage. The additional energy highlighted in light blue in Figure 16 is the energy provided by the pumped storage facility, which would also help close the energy gap in the winter months. The forecast in this Figure is based on the Tutshi-Moon pumped storage project, which has hydrologic inflows that make it a net energy producer rather than a net energy consumer, as detailed in Section 7.

Figure 16: Monthly Renewable Supply vs Demand – Modified (2030)

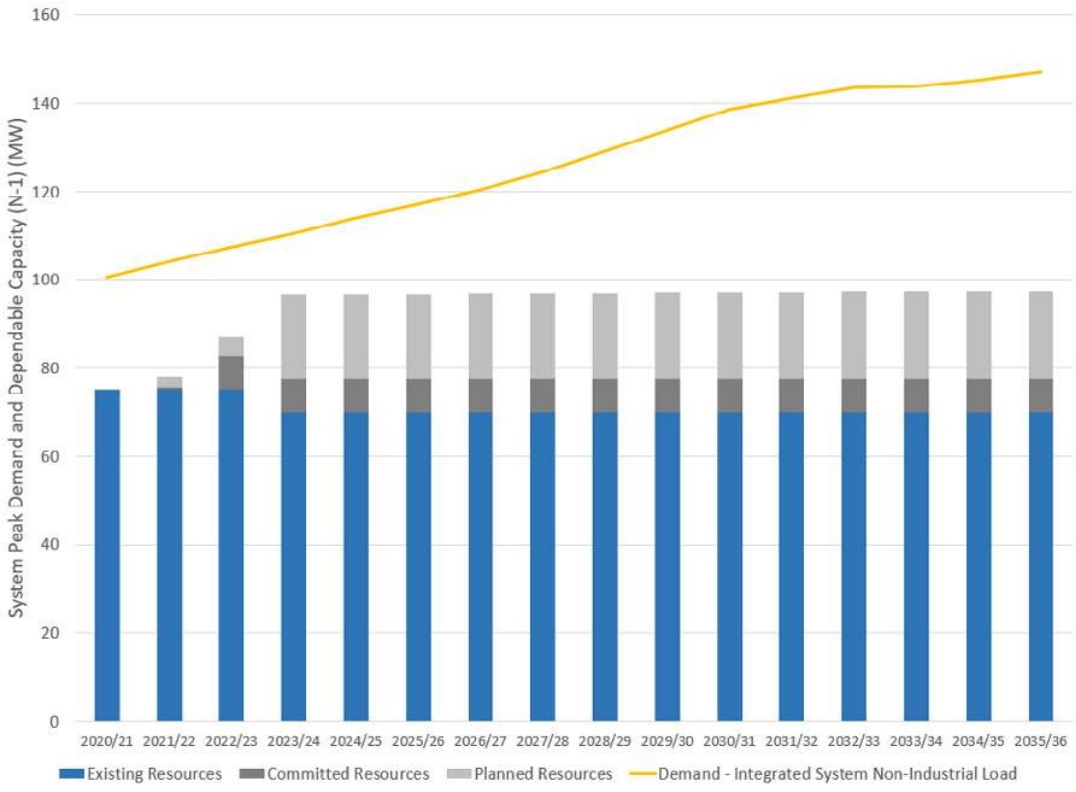


The benefits associated with the productive use of forecast summer surplus energy were the main drivers for incorporating a seasonal pumped storage hydroelectric project and the electrification of Skagway cruise ships as key elements of the 10-Year Renewable Electricity Plan.

6.3 Capacity Gap Analysis

Figure 17 shows the annual gap between the forecasted peak (non-industrial) capacity demand (from Figure 9 in Section 4) and the dependable peak capacity (from Figure 12 in Section 4) under N-1 conditions. The forecast peak capacity gap is significant, growing to approximately 40% of YEC's existing, committed and planned capacity resources. YEC can fill the forecast gap on an interim basis by temporarily renting diesel generators. However, temporary diesel generators have lower reliability and have a higher future availability risk than other resource options. Therefore, finding renewable resource options to fill this peak capacity gap is a priority of the 10-Year Renewable Electricity Plan.

Figure 17: Annual Capacity Gap Analysis under N-1 Conditions (Base Case)



7 Future Potential Resource Options

7.1 Future Potential Resource Options Update Process

The next step in the resource planning process was identifying a list of Future Potential Resource Options to be included in a portfolio that would address the energy and peak capacity gaps identified in Section 6. In order to develop a list of Future Potential Resource Options, the resource options from YEC's 2016 Integrated Resource Plan were updated in three (3) stages:

» **Stage 1:** Refined List of Resources;

» **Stage 2:** Updated Technical Attributes; and

» **Stage 3:** Updated Financial Attributes.

It is important to acknowledge that a comprehensive evaluation of environmental and socio-economic attributes of each resource option was included in the 2016 IRP. Since no showstoppers prohibiting the resource options under consideration in this report were identified during that analysis, these environmental and socio-economic attributes were not re-evaluated as part of the 10-Year Renewable Electricity Plan. If the projects identified in the Plan move forward, detailed environmental and socio-economic analyses and assessments will be carried out as part each project's planning.

7.1.1 Stage 1: Refined List of Resources

In Stage 1, all resource options considered in the 2016 IRP were refined into a subset of preferred resource options. Resource options that were deemed to be fundamentally uneconomic, located too far from existing or proposed transmission infrastructure, too large for the need, or that have been superseded by other options were eliminated from the list. The Committed and Planned Resources described in Sections 5.1.2 and 5.1.3 were also removed from the list because they are assumed to be in operation as per previous plans. The refinement process reduced the 92 resource options evaluated in the 2016 IRP down to 19 resource options (excluding DSM and transmission options).

7.1.2 Stage 2: Technical Attribute Update

In Stage 2, the technical attributes of the refined resource options identified in Stage 1 were updated to reflect current available information. Updates were made to the technical attributes considered in the 2016 IRP such as annual energy, firm energy, installed capacity, dependable capacity, project life, lead time, and resource dispatchability.

The technical attributes from the 2016 IRP were used for the refined list of resource options from Stage 1, except for options which have been studied further since that time. The updated resource options included:

- **Small Hydro.** Knight Piésold Ltd. (KP) was engaged by YEC to update and further develop a desktop review of the potential hydroelectric projects in Yukon and northern BC, provided in Appendix E. This study resulted in a refined and updated list of five (5) small hydroelectric projects of interest, with capacities ranging from 8 MW to 13 MW.
- **Pumped Storage Hydro.** KP was engaged by YEC to update and further develop the Tutshi-Moon pumped storage project. As part of this study, four separate development options with varying levels of installed capacity and winter generating capability were evaluated. The study is provided in Appendix F.
- **Wind.** Although the wind resources have not been studied further since the 2016 IRP, indicative wind sites with varying installed capacities are included in the refined list of resource options. Future wind resources could be implemented either by YEC or by IPPs via a Call for Power.
- **Geothermal.** EAVOR was approached to provide technical and financial details regarding a new geothermal technology being developed in Alberta called the Eavor-Loop technology. The technology was assessed as not being sufficiently mature and commercially proven for consideration as a potential utility resource option. Therefore, an assumption was made that early implementations of the technology would be made via the IPP SOP program. As a result, the technology was excluded from the refined list of resource options.
- **Thermal-Diesel.** Generic permanent and temporary diesel options are included as part of the refined list of resources. They are flexible, scalable, and can be used to help bridge dependable capacity gaps (but not long-term energy gaps). The updated technical attributes associated with these projects were extracted from a series of thermal generation project assessments completed by Midgard Consulting Inc. (Midgard).

7.1.3 Stage 3: Financial Attribute Update

In Stage 3, the financial attributes of the refined list of resource options identified in Stage 1 were updated. The financial attributes considered in the 2016 IRP included the Levelized Cost of Energy (LCOE) and the Levelized Cost of Capacity (LCOC). These were calculated utilizing inputs that include the annualized estimated capital (CAPEX) and operating & maintenance (O&M) costs for each project.

The process for updating these attributes is summarized below:

» **CAPEX Update**. For mature technologies such as hydro and thermal, the CAPEX from the 2016 IRP were inflated to 2019 dollars assuming a 2% inflation rate. The CAPEX for the Small Hydro and Pumped Storage Hydro projects were estimated separately by KP. For maturing technologies including solar and wind, a desktop study was completed to evaluate recent trends in total installed costs. It should be noted that:

- The capital costs of the Atlin Hydro Expansion and the Tutshi-Moon Pumped Storage Hydro Projects were considered with and without Federal funding. Since the completion of this analysis, further work has indicated that additional costs for the Atlin-Jakes Corner transmission must be considered as art of the Atlin Hydro Expansion Project, adding approximately $50 million in capital costs. This will increase the required Federal funding for the project.

- A new 138 kV transmission line from Whitehorse to Skagway (AK) via Carcross (YT), which would be required to connect projects in the Southern Lakes area, was assumed to be supported with up to 75% Federal funding. The transmission cost assumptions associated with projects located near the new transmission line assume an interconnection to this proposed line.

» **O&M Update.** The annualized O&M for the Small Hydro and Pumped Storage Hydro projects in the KP studies were updated. The O&M cost assumptions for all other options were taken from the 2016 Resource Plan, inflated to 2019 dollars assuming a 2% inflation rate.

» **Financial Modelling Update.** Based on the updated set of technical and financial attributes, YEC completed financial modelling to determine the updated LCOE and LCOC associated with the refined list of resource options.



7.2 Future Potential Resource Options

Table 3: Refined List of Future Potential Resource Options

IRP Resource	Options	Installed Capacity (MW)	Dependable Capacity (MW)	Lead Time (Years)	
Hydro Uprate	Aishihik Hydro 1 & Hydro 2 Uprate	1.3 MW	1.3 MW	3 Years	
Small hydro	Primrose (Storage)	13.0 MW	13.0 MW	6 Years	
	Drury (Storage)	10.0 MW	10.0 MW	6 Years	
	Tutshi Windy Arm (Storage)	10.0 MW	10.0 MW	6 Years	
	Wolf River (ROR)	11.0 MW	4.0 MW	6 Years	
	Atlin Hydro Expansion (Storage)	6.0 MW	6.0 MW	5 Years	
	Atlin Hydro Expansion (Storage) with Federal funding	6.0 MW	6.0 MW	5 Years	
Wind	Wind Resource 1	6.0 MW	0.0 MW	5 Years	
	Wind Resource 2	10.0 MW	0.0 MW	5 Years	
	Wind Resource 3	20.0 MW	0.0 MW	5 Years	
Solar	Whitehorse Solar 1	1.0 MW	0.0 MW	2 Years	
	Whitehorse Solar 2	5.0 MW	0.0 MW	2 Years	
	Whitehorse Solar 3	10.0 MW	0.0 MW	2 Years	
Diesel (Comparator)	Generic Greenfield Permanent @ Takhini	10.0 MW	10.0 MW	4 Years	
	Generic Rental @ Whitehorse Substation S150	2.0 MW	2.0 MW	0 Years	
Pumped Storage	Tutshi-Moon (15MW-25GWh)	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (15MW-45GWh)	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (25MW-50GWh)	25.0 MW	25.0 MW	6 Years	
	Tutshi-Moon (35MW-50GWh)	35.0 MW	35.0 MW	6 Years	
	Tutshi-Moon (15MW-25GWh with Federal Funding	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (15MW-45GWh with Federal Funding	15.0 MW	15.0 MW	6 Years	
	Tutshi-Moon (25MW-50GWh with Federal Funding	25.0 MW	25.0 MW	6 Years	
	Tutshi-Moon (35MW-50GWh) with Federal Funding	35.0 MW	35.0 MW	6 Years	
Energy Storage	Lithium-ion	8.0 MW	8.0 MW	2 Years	

Table 3 is a summary of the 19 Future Potential Resources considered in the 10-Year Renewable Electricity Plan along with their associated technical and financial attributes.

	Annual Energy (MWh/Yr)	CAPEX ($2019)	O&M		LCOC ($/kW-Yr)	LCOE ($/kWh-Yr)
			Fixed ($2019/Yr)	Variable ($2019/MWh)		
	2,700 MWh	$5,300,000	$0	$5.31	$185	$0.09
	74,100 MWh	$177,500,000	$3,900,000	$5.00	$797	$0.14
	30,600 MWh	$110,500,000	$2,400,000	$5.00	$635	$0.21
	49,300 MWh	$135,600,000	$3,700,000	$5.00	$860	$0.17
	79,700 MWh	$165,100,000	$3,600,000	$5.00	$2,417	$0.12
	44,700 MWh	$131,000,000	$2,900,000	$5.00	$1,270	$0.17
	44,700 MWh	$32,750,000	$2,900,000	$5.00	$708	$0.10
	18,100 MWh	$39,500,000	$280,000	$27.26	Not supplied	$0.17
	29,500 MWh	$49,200,000	$290,000	$21.81	Not supplied	$0.13
	57,300 MWh	$73,500,000	$340,000	$21.40	Not supplied	$0.10
	1,100 MWh	$2,300,000	$30,000	$0.00	Not supplied	$0.13
	5,600 MWh	$8,100,000	$150,000	$0.00	Not supplied	$0.10
	11,500 MWh	$16,100,000	$340,000	$0.00	Not supplied	$0.10
	2,500 MWh	$25,600,000	$170,000	$22.00	$131	$0.53
	2,500 MWh	$0.00	$280,000	$0.00	$243	Not Supplied
	19,900 MWh	$182,500,000	$2,020,000	$0.00	$552	$0.42
	14,000 MWh	$194,200,000	$2,050,000	$0.00	$581	$0.62
	12,000 MWh	$245,000,000	$2,100,000	$0.00	$421	$0.88
	10,000 MWh	$280,000,000	$2,150,000	$0.00	$336	$1.18
	19,900 MWh	$45,625,000	$2,020,000	$0.00	$239	$0.18
	14,000 MWh	$48,550,000	$2,050,000	$0.00	$248	$0.27
	12,000 MWh	$61,250,000	$2,100,000	$0.00	$168	$0.35
	10,000 MWh	$70,000,000	$2,150,000	$0.00	$130	$0.46
	2,800 MWh	$29,500,000	$280,000	$0.00	$280	Not Supplied

7.3 Future Potential Resource Observations

1. **Intermittent renewables do not contribute capacity.** Resources such as wind and solar offer relatively low levelized costs for energy (LCOE), but do not provide dependable capacity to the Yukon system. This is because they can only generate electricity while their energy source is available (e.g. the sun is shining and/or the wind is blowing). As a result, these resources cannot address YEC's key challenge of closing the existing and forecast peak capacity gap. In addition, since solar resources are summer peaking generation resources, integrating more solar resources increases the quantity of surplus summer energy.

2. **Small Hydro.** In general, this is an attractive resource because it offers reasonably priced energy and capacity in a single project. The Atlin Hydro Expansion project is preferred based on its shorter project development timeline when compared to the other small hydro options.

3. **Tutshi-Moon Pumped Storage Hydro Inflows & Seasonal Shifting.** This project would be used for seasonal energy storage, storing excess summer energy (in the form of water held in the upper reservoir) for generation during the winter. This means that pumping water into the reservoir for storage will occur during the summer months when there is surplus energy available, and generation will occur during the winter months when electricity demand increases. In addition, the Tutshi-Moon pumped storage project is expected to have hydrologic inflows that make it a net energy producer. Typical pumped storage hydro projects are net energy consumers due to the energy losses associated with the water pumping process. Since the pumped storage hydro options evaluated are not cost competitive on a LCOC basis compared to greenfield diesel generation or diesel generator rentals without grant funding, Federal funding is required to bring the LCOC of pumped storage hydro in line with that of diesel. Finally, there are economies of scale with regards to the LCOC for the Tutshi-Moon pumped storage project, such that upscaling the project to reduce the project LCOC is justifiable.

4. **Federal Funding**. Securing Federal funding to help finance the Atlin Hydro Expansion and Tutshi-Moon pumped storage hydro projects is required to bring the cost of energy and capacity from these projects down, thereby reducing the impacts of these projects on electricity rates in Yukon. Without Federal funding, these projects are not considered cost-competitive and would most likely not be approved by the Yukon Utilities Board.

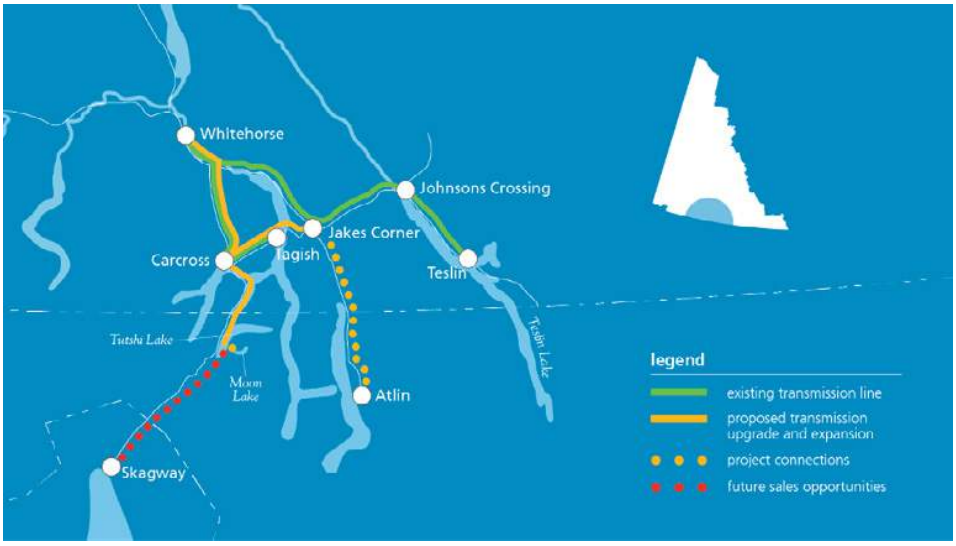
5. **Aishihik Uprate Capacity.** The 1.3 MW dependable capacity associated with the Aishihik Hydro 1 and Hydro 2 uprate projects is only considered available if the loss of Aishihik is no longer the largest single contingency event (N-1 Event) on the YIS.

7.4 Southern Lakes Transmission Project

Given the limitations of existing transmission in the Southern Lakes area and the requirement to connect new projects, upgrading and expanding the transmission infrastructure in the Southern Lakes area is a necessary element of this plan.

This plan assumes that a new transmission line from Skagway (AK) to Whitehorse through Carcross (YT) will be built in a phased manner to support the development of the Southern Lakes area as illustrated in Figure 18. This is a 138 kV transmission line with sufficient transmission capacity to accommodate the full portfolio of future planned projects. In order to minimize intrusion into the natural environment, the proposed line will follow existing rights of way where possible (e.g. highway, transmission or rail).

Figure 18: Southern Lakes Transmission Network



The proposed development of this line follows a phased approach:

» **Phase 1.** This phase includes the construction of the Whitehorse -> Carcross -> Jakes Corner section of the line transmitting power from the Atlin Hydro Expansion project to the load centre at Whitehorse. It should be noted that the viability of connecting the Atlin Hydro Expansion project to the existing ATCO distribution system at Jakes Corner is currently being assessed as an interim measure. By decoupling the timing of the Atlin Hydro Expansion project from that of the Southern Lakes Transmission Project, the Atlin Hydro Expansion project can move forward as soon as possible

» **Phase 2.** This would extend the line from Carcross (YT) to Moon Lake (BC) to interconnect the proposed Tutshi-Moon Pumped Storage Hydro project. The execution of this phase is contingent on the timing and implementation of the proposed Tutshi-Moon Pumped Storage Hydro project.

» **Phase 3.** The final phase of the project would involve an extension of the line from Moon Lake (BC) to Skagway (AK) to complete the 138 kV interconnection from Whitehorse (YT) to Skagway (AK). This final phase will only proceed if and when YEC secures summer energy sales to Skagway for the purposes of providing shore-side power to cruise ships.

Some flexibility is assumed in the sequencing of the transmission construction phases outlined above. For example, it is conceivable that the Whitehorse-Carcross-Skagway line could be constructed in a single step if Yukon Energy is able to advance the business opportunity to sell power to cruise ships in Skagway.

8 Preferred Resource Portfolios

8.1 Portfolio Analysis Methodology

The goal of portfolio analysis is to develop an optimal set of projects capable of addressing both the energy and peak capacity shortfalls over the 10-year planning horizon. YEC's methodology was to follow a directed portfolio development that focused on projects clustered in the Southern Lakes area, facilitated by a Federally supported build-out of transmission infrastructure in that area.

The following assumptions were made in the development of the project portfolio:

1. **Federal Funding.** An assumption was made that Federal funding would be available to protect ratepayers from the impacts of developing significant new infrastructure projects. In order to achieve or exceed the 93% renewable portfolio standard policy objective, Federal funding is also necessary to improve the economics of certain renewable resource options (e.g. pumped storage hydro) relative to the lowest cost fossil fuel-based options.

2. **Committed and Planned Resources Will Happen.** The portfolios assume that the Committed and Planned Resources (previously described in Sections 5.1.2 and 5.1.3), including demand side management programs, are developed and implemented in their respectively planned years.

3. **Atlin Hydro Expansion.** This project is included in the portfolio because of its ability to supply both dependable capacity and firm energy, and because of its significantly shorter project development timeline when compared to other greenfield hydro options.

4. **Tutshi-Moon Pumped Storage Hydro.** This project will provide a significant increase in renewable dependable capacity to address Yukon's existing and forecast capacity shortfall. At the same time, it presents an opportunity to utilize surplus summer energy to meet the forecast winter energy shortfall.

5. **Southern Lakes Transmission build-out.** A new transmission line is required to connect identified projects in the plan (Tutshi-Moon Pumped Storage Hydro; Atlin Hydro Expansion) to the Yukon grid. The development of a new transmission line also facilitates the connection of renewable energy projects developed under the IPP SOP in the Southern Lakes Area, and enables the potential for future sales of surplus summer energy to Skagway for the provision of shore-side power to summertime cruise ships.

6. **Intermittent Renewables (Wind).** These are included as required to meet any residual energy gaps not filled by Tutshi-Moon Pumped Storage Hydro and Atlin Hydro Expansion projects (e.g. in the high load scenario).

7. **Bridging Residual Energy Gaps.** Existing thermal LNG generation is assumed to be available to bridge any small outstanding gaps between average energy and forecast energy demand over the planning period.

8. **Bridging Residual Capacity Gaps.** Temporary rental diesel units are assumed to be available to bridge any outstanding gap between the forecast dependable capacity generation and peak capacity demand over the planning period.

9. **Portfolio Economics Check.** Once the portfolios were built, the Net Present Value of each portfolio was compared to find the lowest cost portfolios which are presented in this report.

The output of the portfolio analysis was an optimum set of resource options that meets the energy and capacity planning criteria under each scenario. The preferred portfolios for the expected Base Case scenario as well as the High Case are presented in the following section. Preferred portfolio analysis results for the Low Case and the Base Case (without Skagway) are provided in Appendix C:

8.2 Preferred Portfolios

The portfolios for the Base Case and High Case scenarios, are presented in the following format:

» **Planning Horizon.** Although the planning horizon for the 10-Year Renewable Electricity Plan is from 2020 to 2030, the annual energy and peak demand forecasts are shown over a longer timeframe (i.e. 2020 to 2035) to show the phased development of certain resource options included in the portfolio (e.g. Tutshi-Moon Pumped Storage Hydro).

» **Annual Energy.** These forecasts show the annual energy demand and average energy generation for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Peak Capacity Demand.** These forecasts show the peak capacity demand requirement under the N-1 planning criterion, and the dependable capacity for Existing, Committed, Planned, and Future Potential Resources over the planning horizon.

» **Portfolio Summary**. This table lists Future Potential Resources with their respective in-service dates and installed capacities.

» **Portfolio Capital Cost.** This table shows the simple (undiscounted) value of the capital expenditures for Future Potential Resources and the Southern Lakes Transmission Project over the 10-year planning period, both with and without Federal funding (assumed to be the typical maximum 75% of capital cost). For the Base Case and High Case, all three phases of the Southern Lakes Transmission Project are included (e.g. the line extends from Whitehorse, YT to Skagway, AK). These costs include future projects that may be developed by both YEC and/or independent power producers. This does not include the costs of the Committed and Planned Resources in each plan. The Portfolio Capital Cost was presented for illustrative purposes to show the magnitude of undiscounted capital investment over the planning period.

8.2.1 Base Case Portfolio

Figure 19: Base Case Portfolio, Energy

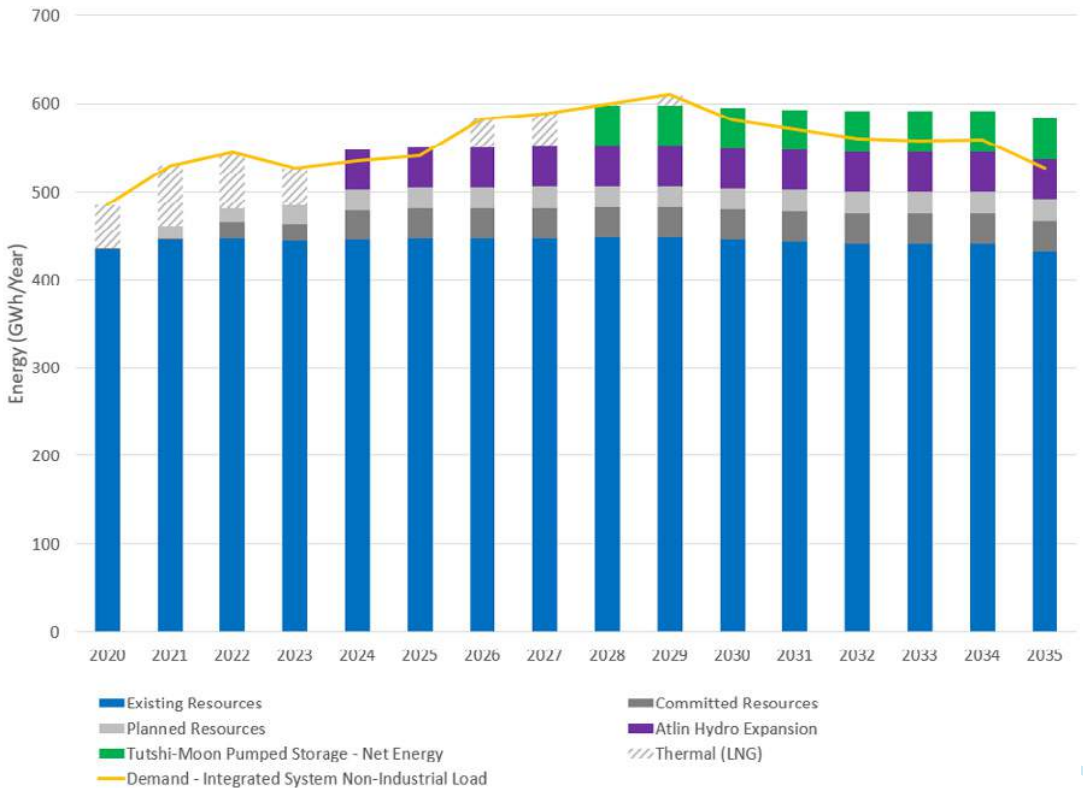


Figure 20: Base Case Portfolio, Capacity

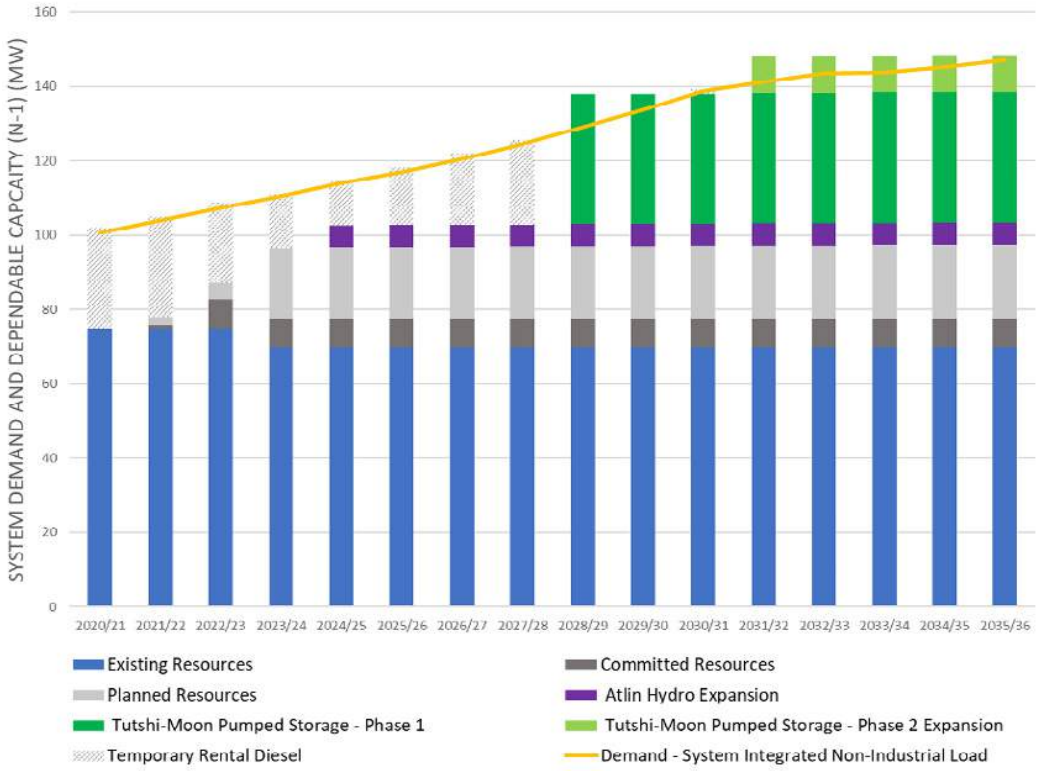


Table 4: Base Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table 5: Base Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 577 million
Portfolio Capital Cost with Federal Funding:	$ 144 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.2.2 High Case Portfolio

Figure 21: High Case Portfolio, Energy

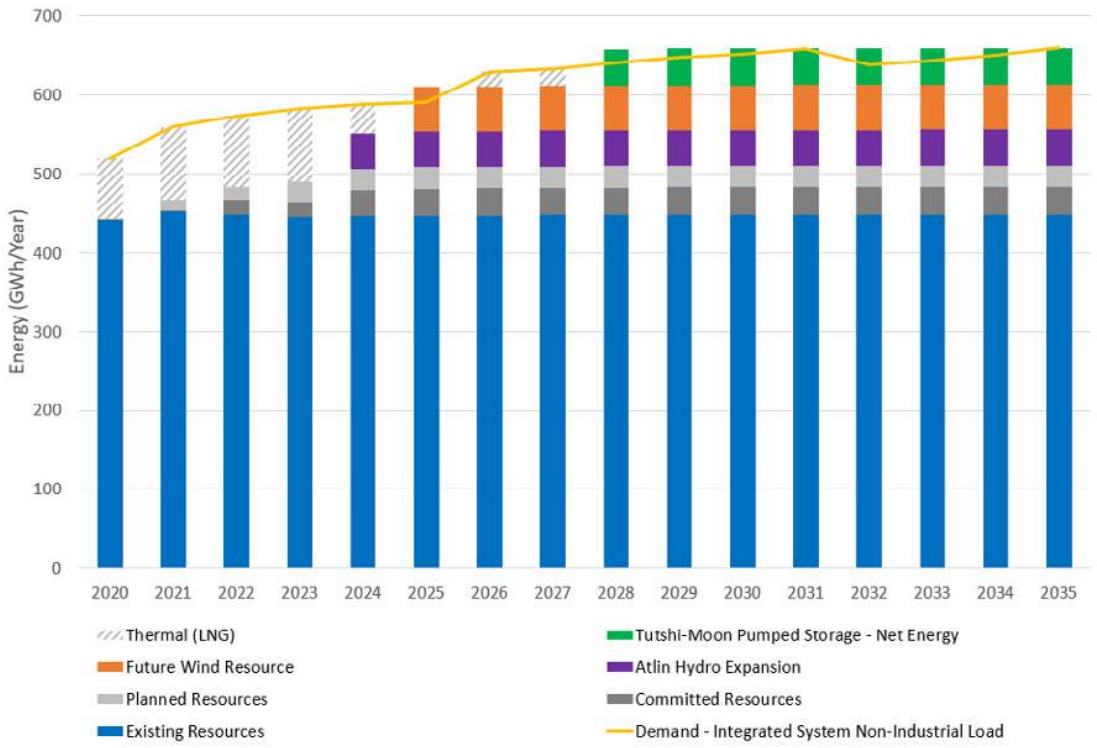


Figure 22: High Case Portfolio, Capacity

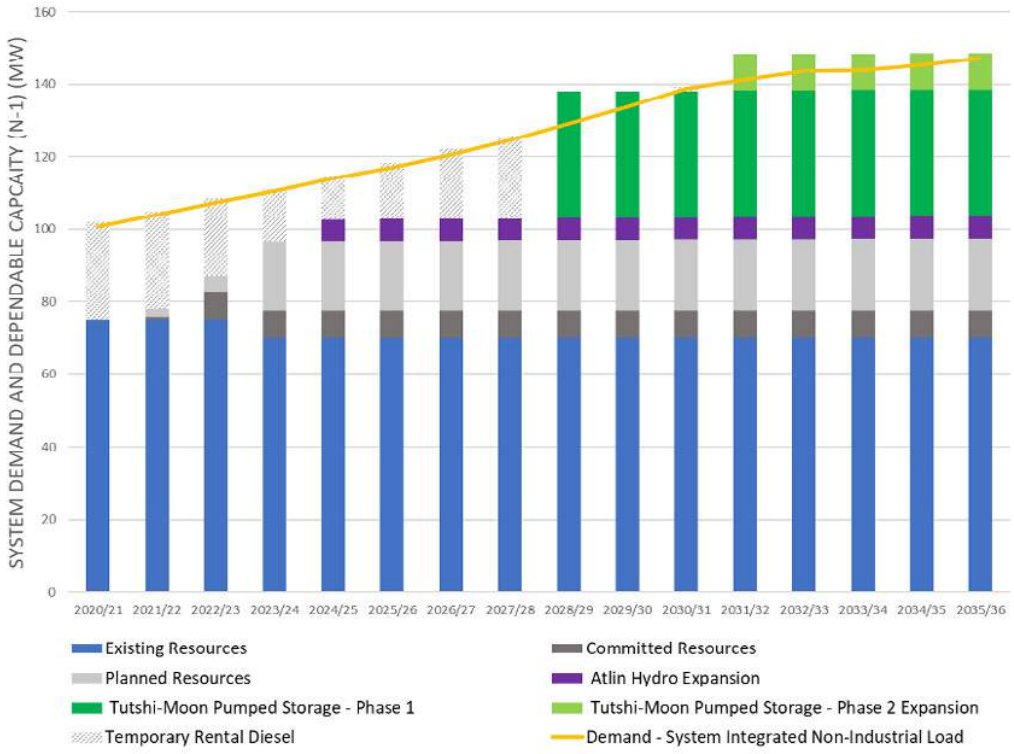


Table 6: High Case Portfolio Summary (2020 – 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2025/26 Wind Resource Project	20	0
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**89.9**	**68.1**

Table 7: High Case Portfolio Cost Summary (2020 – 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 651 million
Portfolio Capital Cost with Federal Funding:	$ 163 million

Appendix D: provides a more detailed breakdown of the cost and capacity components for the Base Case.

8.3 Portfolio Summary

As a consequence of the long lead times associated with developing generation and transmission, the portfolios show an energy and dependable capacity shortfall over the planning period, especially in the early years. As a result, residual energy and capacity gaps are assumed to be met with LNG generation and temporary diesel generator rentals over the planning period. Conversely, the Base Case scenario shows an energy surplus after 2030 based on the forecast decrease in industrial load, which indicates that the net energy production from the pumped storage facility would be in surplus. Federal funding will be critical in order to protect ratepayers from the financial cost of this potential surplus.

A summary of the resource options comprising the Base Case and the High Case scenario portfolios is presented in Table 8. Implementation of both the Atlin Hydro Expansion project in year 2024/25 and phase 1 of the Tutshi-Moon Lake Pumped Storage Project in year 2028/29 is required for both portfolios. Finally, the High Case scenario also requires a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period.

Table 8: Future Resources Selected for Key Scenarios

	BASE CASE	HIGH CASE
2024/25	Atlin Hydro Expansion (6 MW)	Atlin Hydro Expansion (6 MW)
2025/26		Wind Resource (20 MW)
2028/29	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)	Tutshi-Moon Pumped Storage Project – Phase 1 (35 MW)
Total Portfolio Capital Cost without Federal Funding ($M)	**$577 Million**	**$651 Million**
Total Portfolio Capital Cost with Federal Funding ($M)	**$144 Million**	**$163 Million**

8.3.1 Southern Lakes Geographic Focus

The 10-Year Renewable Electricity Plan's underlying focus on clean energy and capacity resources led to the development of multiple solutions in the Southern Lakes area, the geographical area shown in Figure 23.

Figure 23: Southern Lakes Transmission Network



With its abundance of lakes and proximity to Whitehorse (Yukon's main population and electrical load centre), the Southern Lakes area is well suited for developing hydroelectric resources. Hydroelectric and pumped storage hydro screening studies were completed as part of the 2016 Integrated Resource Plan. These studies identified several potential project sites in the Southern Lakes area, including the Tutshi-Windy Arm and Surprise Lake hydroelectric project sites, as well as the Moon-Tutshi, Racine-Moon, Lindeman-Fraser, Racine-Mount Brown and Atlin-Black Mountain pumped storage hydro sites. These general findings were confirmed in the study updates discussed in Section 7.1. Prospective Independent Power Producer (IPP) projects have also been identified in the Southern Lakes area, including the Atlin Hydro Expansion project and the Montana Mountain Wind and Solar Projects.

Given the limited existing transmission assets in the Southern Lakes area and the requirement to interconnect new projects, upgrading and expanding the transmission infrastructure is a requirement for enabling the projects in the Southern Lakes area. It may also be possible for YEC to take advantage of a potentially attractive business opportunity to supply electricity to cruise ships docking in Skagway during the summer tourist season. Currently, the Skagway pier has the capability to interconnect up to four (4) cruise ships, which can amount to approximately 35 GWh/year of summer energy demand. Cruise ships visiting Skagway today burn diesel fuel to generate shipboard electricity while at the dock. Electrifying cruise ships using surplus energy available during the summer months could lead to increased revenues for Yukoners to offset Yukon electricity costs, and a reduction in GHG emissions in Skagway. As noted in Section 4.2, this analysis was conducted prior to the COVID-19 pandemic; YEC will assess the timing and extent of the recovery of the cruise ship industry as part of its evaluation of the Skagway business opportunity.

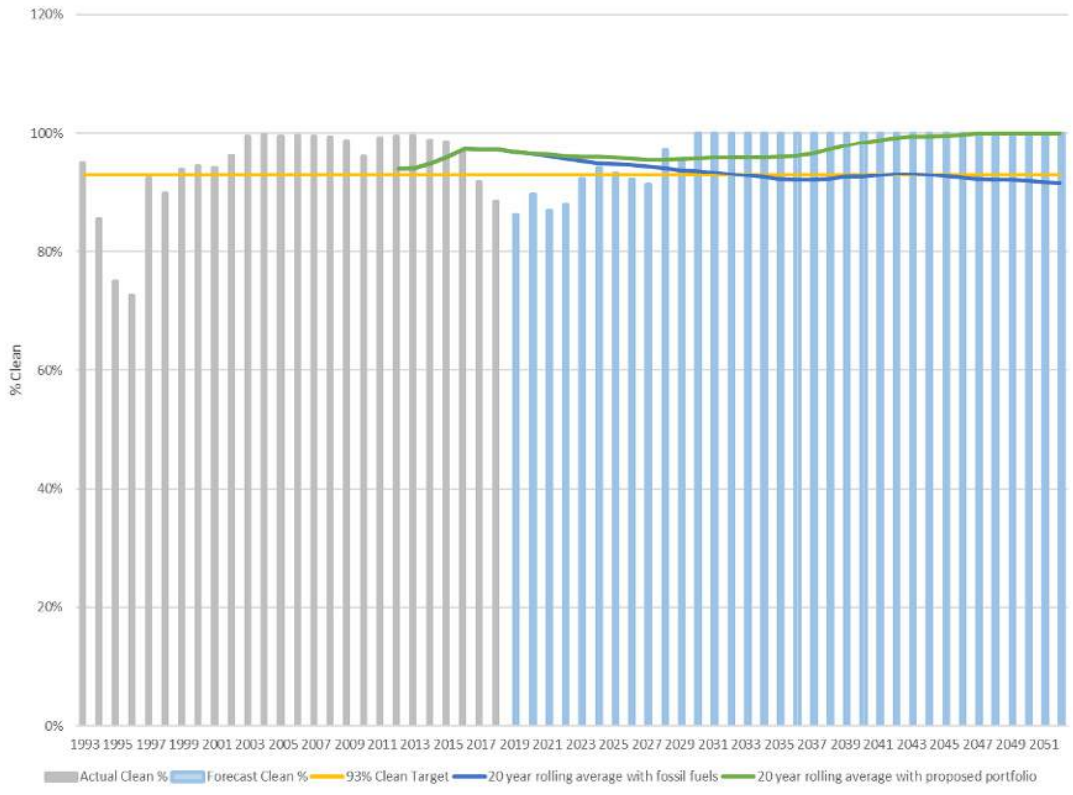
The majority of the new generation in the Plan is located in British Columbia; however, Yukoners will be receiving the benefits of the greenhouse gas emissions reductions and renewable electricity provision. YEC will strive to maximize other benefits to Yukoners via contracting and procurement opportunities and Yukon First Nations benefits agreements. YEC will also continue to work with both the Yukon and BC governments to ensure key stakeholders are engaged appropriately.

8.4 Renewable Portfolio Target

Under the Yukon government's draft Climate Change, Energy and Green Economy strategy, YEC is mandated to meet a renewable portfolio target of 93% on a long-term average basis. This means that at least 93% of the electricity generated on the YIS has to come from renewable sources.

Figure 24 illustrates the forecast percentage renewable generation profile of the electricity mix assuming that the 10-Year Renewable Electricity Plan portfolio is successfully executed. For comparison, the figure also includes a forecast percentage renewable generation profile for an alternate portfolio with a heavy reliance on fossil fuels to meet forecast energy needs (i.e., the portfolio that would be required if the 10-Year Renewable Electricity Plan is not implemented).

Figure 24: Long Term Energy Generation Profile



The bars shown in Figure 24 represent the actual percentage of renewable energy being generated by the system. The gap between the bars and the 100% threshold represents the percentage of energy generated by non-renewable resources (e.g. thermal). The lower percentage of renewable generation observed in recent years (i.e. 2017-2020) was a result of increased thermal generation at the margin given load growth and low hydroelectric resources (drought conditions) in these years.

As new renewable supply projects are developed over the planning period, there is an observed increase in percentage renewables in the energy generation mix. As observed in Figure 24, the 10-Year Renewable Electricity Plan portfolio exceeds the 93% renewable target over the planning period and beyond. The portfolio of projects recommended in the 10-Year Renewable Electricity Plan delivers on Yukon government's commitment for GHG reductions by 2030. It positions YEC favourably to contribute towards achieving the Federal government's "net zero by 2050" target.



9 10-Year Renewable Energy Action Plan

This section presents the key considerations in developing the 10-Year Renewable Electricity Action Plan (Action Plan), and the proposed steps to be undertaken to implement it.

9.1 Project Development Plan

The recommended Action Plan is based on developing the resource portfolio generated for the Base Case scenario, with add-on resources identified for other scenarios. Figure 25 summarizes the Action Plan recommendations.

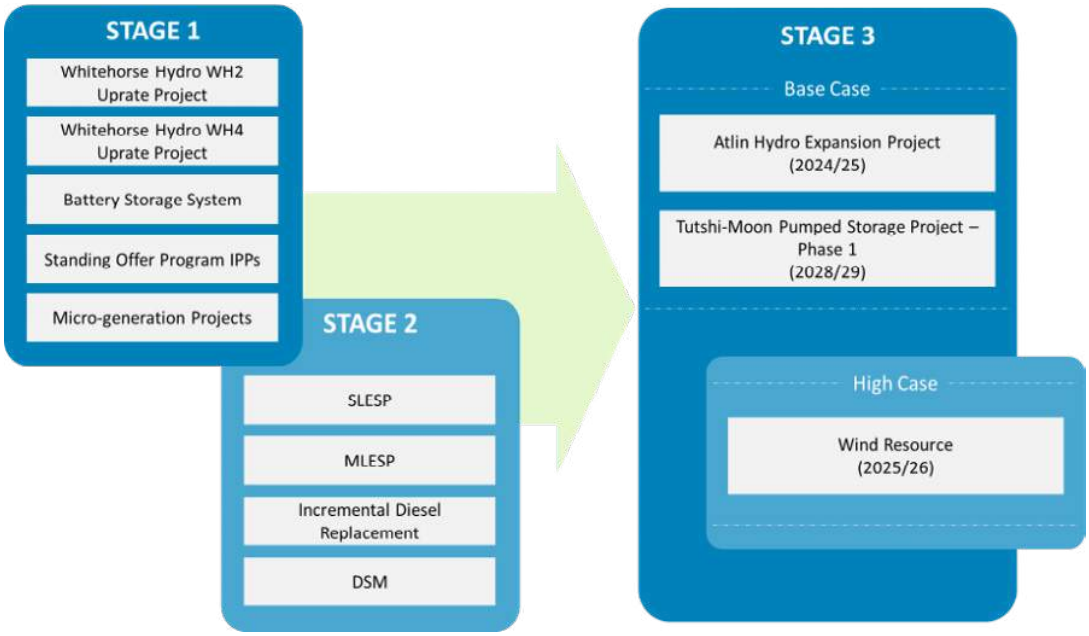
The Action Plan is divided into three stages:

» **Stage 1 – Implementation of the Committed Resources.** These resources are essential in all the portfolios over the planning period. These common resources include the Whitehorse Hydro #2 and #4 (WH2 and WH4) Uprate Projects, Battery Storage System, SOP IPP, and Micro-generation projects.

» **Stage 2 – Completion of Planning Work & Final Decisions to Proceed with Planned Resources.** These common resources include the SLESP, MLESP, the Incremental Diesel Replacement, and DSM.

» **Stage 3 – Development and implementation of the Future Potential Resources.** The options recommended for the expected Base Case scenario are the Atlin Hydro Expansion Project and Phase 1 of the Tutshi-Moon Lake Pumped Storage Project. The additional Future Potential Resource option included in the High Case portfolio (i.e. the Wind Resource) is considered as potential add-on resource to the Action Plan but is ultimately contingent on future growth.

Figure 25: 10-Year Renewable Electricity Action Plan



As with all long-term resource plans, there is the potential for future changes to trigger changes to the path forward. YEC will continue to monitor the key elements that influence the Plan, including the load forecast, progress or obstacles in executing the projects, and developments in emerging or uncertain technologies, and will update the path forward in future long-term resource planning exercises accordingly.

9.2 Key Risks & Uncertainties

The key risks and uncertainties with regard to the 10-year Renewable Electricity Plan are described below. If YEC is unable to move forward with the projects in the Plan, a new plan will be required to address Yukon's load growth and renewable electricity requirements.

» **Federal Funding Uncertainty.** The Action Plan assumes that Federal funding will be secured for the development of the identified generation projects and the supporting Southern Lakes transmission infrastructure. As such, Federal funding is an essential part of the recommended Action Plan as it will help minimize the rate impacts of the plan for Yukoners, and protect ratepayers from contingent risks such as the premature loss of industrial load. However, securing federal funding is not a certainty. To mitigate this risk, options to phase the Federal funding requests, such as focusing on securing funding for project planning first, and only proceeding with project construction once construction funding has been secured, will be explored with Federal funding agencies in order to mitigate risks. YEC will also coordinate closely with Yukon government and potential First Nations project developers and partners in pursuit of this Federal funding. If YEC is unable to secure Federal funding, a new long-term resource plan will need to be developed, as it is a critical requirement for the execution of the 10-Year Renewable Electricity Plan.

» **General Development Risks.** There is always some potential for technical or financial problems during project planning or construction, which could result in abandoning specific lower cost resources in favor of more expensive resources and/or delays. The resulting impacts include higher rates driven by increased portfolio costs and/or insufficient energy and/or capacity supply.

» **Residual Ratepayer Risk (exposure to surplus energy/mismatch).** If the future load projections used to justify capital plans do not materialize, over-building and/or over-production of electricity from the IPP SOP or micro-generation programs could lead to additional surplus energy and a seasonal mismatch between available generation and demand. This poses a financial risk to ratepayers in the form of higher rates.

» **SOP IPP Uncertainty.** The possibility of bankruptcy or failure of contracted generation assets, or the failure of contracted IPPs to reach commercial operation (multiple causes) could result in some IPP projects being delayed or not completed. The resulting risks include the inability to achieve renewable energy targets, increased thermal energy requirements, and/or insufficient energy supply.

» **Regulatory Uncertainties.** These uncertainties could lead to proposed electricity supply projects being disallowed by the regulator or to protracted legal and regulatory processes delaying project approvals or relicensing. If these projects are delayed or canceled, it will result in increased reliance on thermal generation for energy, and ongoing rental of temporary diesel engines for capacity. The resulting risks include the inability to achieve renewable energy targets, and potential rate increases caused by increased portfolio costs due to burning higher cost fossil fuels and introducing more expensive replacement projects.

9.3 First Nations Engagement, Support and Participation

Active First Nations participation in and support for the plan will be vital to the successful execution of the plan. YEC will be actively engaging with those First Nations on whose Traditional Territory the proposed projects are located.

Opportunities exist for First Nations to participate in multiple components of the plan, including the IPP SOP, and by taking an active role as project proponents and/or partners in the 10-Year Renewable Electricity Plan. In addition, First Nations will have contracting and other business opportunities during project planning and construction. These opportunities will be explored in detail during all phases of the project development.

Specific First Nations engagement plans for the two highest priority Future Potential Resources is outlined below:

» **Atlin Hydro Expansion project:** this project is being developed as an Independent Power Producer project by Tlingit Homeland Energy LP (THELP), a corporation owned by the development corporation of the Taku River Tlingit First Nation (TRTFN). As such, THELP will be responsible for all aspects of the project development, including environmental assessment and permitting, engineering design, construction and community and First Nations consultation. Yukon Energy has engaged in negotiations with THELP on a potential Electricity Purchase Agreement (EPA), which will outline the key commercial and operations terms under which YEC would purchase electricity from the Atlin Hydro Expansion project, should the project be approved to proceed. YEC and THELP are actively collaborating on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the price of energy and capacity procured under the EPA affordable to Yukon customers.

- **Moon Lake Pump Storage Project:** this project is located on overlapping Traditional Territory of the Carcross/Tagish First Nation (C/TFN) and the Taku River Tlingit First Nation. As such, YEC plans to actively engage with both First Nations on the development of the Moon Lake Pump Storage project. As of Q4 2020, the project remains in a very early stage of development, and work completed to date has been limited to desk-top engineering and technical studies. YEC plans to engage with both C/TFN and TRTFN to establish a framework agreement covering the initial stages of project assessment and development, with the intent to undertake all field work, environmental assessment and monitoring, engineering design and community engagement in a collaborative, transparent manner. Options for the ultimate ownership structure of the project, including options for either partial of full ownership by First Nations, will also be assessed and negotiated over the initial phase of project planning. YEC will also actively collaborate with C/TFN and TRTFN on securing government grant funding for the project, which will be critical to supporting the project economics while keeping the project affordable for Yukon customers.

Appendix A:
Existing Resources Technical Attributes

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan		2016 IRP Dependable Capacity (IRP Table 4.2.)
						Installed Capacity [kW]	Dependable Capacity [kW]	[kW]
Aishihik								
Hydro	2050	AH1	AH1	Hydro	Yes	15,600	15,000	15,000
	2050	AH2	AH2	Hydro	Yes	15,600	15,000	15,000
	2050	AH3	AH3	Hydro	Yes	7,000	7,000	7,000
					Subtotal	**38,200**	**37,000**	**37,000**
Faro								
Diesel	2023	FD1	FD1	Diesel	Yes	5,150	3,000	4,000
	2050	FD7	FD7	Diesel	Yes	3,000	2,800	2,800
					Subtotal	**8,150**	**5,800**	**6,800**
Dawson								
Diesel	2050	DD1	DD1	Diesel	Yes	800	650	720
	2023	DD2	DD2	Diesel	Yes	1,000	850	920
	2050	DD3	DD3	Diesel	Yes	1,000	850	920
	2050	DD4	FD5	Diesel	Yes	1,440	1,000	1,000
	2023	DD5	DD5	Diesel	Yes	1,500	1,350	1,400
	2050	YM1	FD6	Diesel	Yes	1,440	850	1,000
					Subtotal	**7,180**	**5,550**	**5,960**
Mayo								
Diesel	2050	MD1	FD2	Diesel	Yes	1,000	850	850
	2050	MD2	FD4	Diesel	Yes	1,000	850	850
	2050	MD3	FD3	Diesel	Yes	1,000	850	850
					Subtotal	**3,000**	**2,550**	**2,550**
Hydro	2050	MH1	MH1	Hydro	Yes	2,550	1,500	1,400
	2050	MH2	MH2	Hydro	Yes	2,550		
	2050	MBH1	MBH1	Hydro	Yes	5,310	2,500	3,800
	2050	MBH2	MBH2	Hydro	Yes	5,310	2,500	3,800
					Subtotal	**15,720**	**6,500**	**9,000**
					Total	**18,720**	**9,050**	**11,550**
Whitehorse								
Hydro	2050	WH1	WH1	Hydro	Yes	5,800	3,500	3,000
	2050	WH2	WH2	Hydro	Yes	5,800	3,500	3,000
	2050	WH3	WH3	Hydro	Yes	8,400		
	2050	WH4	WH4	Hydro	Yes	21,327	20,000	18,500
					Subtotal	**41,327**	**27,000**	**24,500**
Diesel	2015	WD1	WG1	Diesel	Yes	N/A	N/A	N/A
	2015	WD2	WG2	Diesel	Yes	N/A	N/A	N/A
	2019	WD3	WD3	Diesel	Yes	N/A	N/A	4,500
	2050	WD4	WD4	Diesel	Yes	2,500	2,250	2,500
	2050	WD5	WD5	Diesel	Yes	2,500	2,250	2,500
	2050	WD6	WD6	Diesel	Yes	2,500	2,250	2,500
	2050	WD7	WD7	Diesel	Yes	3,300	2,800	3,000
					Subtotal	**10,800**	**9,550**	**15,000**
Natural Gas	2055	WG1	WG1	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG2	WG2	Natural Gas	Yes	4,400	4,200	4,400
	2055	WG3	WG3	Natural Gas	Yes	4,400	4,200	N/A
					Subtotal	**13,200**	**12,600**	**8,800**
					Total	**65,327**	**49,150**	**48,300**

Location	Retirement Year	Original Unit #	Current Unit #	Prime Mover Type	Dispatchable	10 Year Renewable Energy Plan Installed Capacity [kW]	10 Year Renewable Energy Plan Dependable Capacity [kW]	2016 IRP Dependable Capacity (IRP Table 4.2.) [kW]
Haeckel Hill								
Wind	2019	WW2	WW2	Wind	No	N/A	N/A	0
						0	**0**	**0**
Mobile Diesels								
Diesel	2050	YM2	YM2	Diesel	Yes	150	0	0
	2050	YM3	YM3	Diesel	Yes	125	0	0
	2050	YM4	YM4	Diesel	Yes	35	0	0
	2050	YM5	YM5	Diesel	Yes	125	0	0
					Subtotal	**435**	**0**	**0**
YECL								
Diesel	2050	CD1	CD1	Diesel	Yes	1,600	1,200	1,206
	2050	TD1	TD1	Diesel	Yes	1,500	1,200	1,130
	2050	RD1	RD1	Diesel	Yes	1,000	750	750
	2050	HD1	HD1	Diesel	Yes	1,750	1,500	1,320
	2050	Pelly G1	Pelly G1	Diesel	Yes	275	200	199
	2050	Pelly G2	Pelly G2	Diesel	Yes	600	400	446
	2050	Pelly G3	Pelly G3	Diesel	Yes	300	200	218
	2050	Stewart G1	Stewart G1	Diesel	Yes	150	100	104
					Subtotal	**7,175**	**5,550**	**5,373**
				YEC	**Hydro**	95,247	70,500	70,500
					Diesel	29,565	23,450	30,310
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0.0
					Total	**138,012**	**106,550**	**109,610**
				YECL	**Diesel**	7,175	5,550	5,373
					Total	**7,175**	**5,550**	**5,373**
				Yukon Power System	**Hydro**	95,247	70,500	70,500
					Diesel	36,740	29,000	35,683
					Natural Gas	13,200	12,600	8,800
					Wind	0	0	0
					Total	**145,187**	**112,100**	**114,983**
				Single Contingency (N-1) Dependable Capacity	**Hydro**	N/A	33,500	33,500
					Diesel	N/A	27,500	34,363
					Natural Gas	N/A	12,600	8,800
					Wind	N/A	0	0
					Total	**0.0**	**73,600**	**76,663**

Notes:
- *Single Contingency (N-1) scenario dependable capacity excludes the dependable capacity for Aishihik (37 MW) and ATCO's Haines junction diesel generator (1.5 MW) as the community would be isolated by the loss of the transmission line between the Aishihik Generating Station and the Takhini substation.*
- *No dependable capcity assumed for Minto Mine diesel generators and YEC wind turbines and mobile generators with the exception of unit YM1.*
- *Excludes ATCO Fish Lake Hydro. The contribution of the ATCO Fish Lake Hydro plant was not included in the inventory of the existing resources as its contribution was deducted from the load forecast modelling.*

Appendix B:
Energy & Capacity Gap

Figure B1: Base Case Energy Gap Analysis: Detailed View

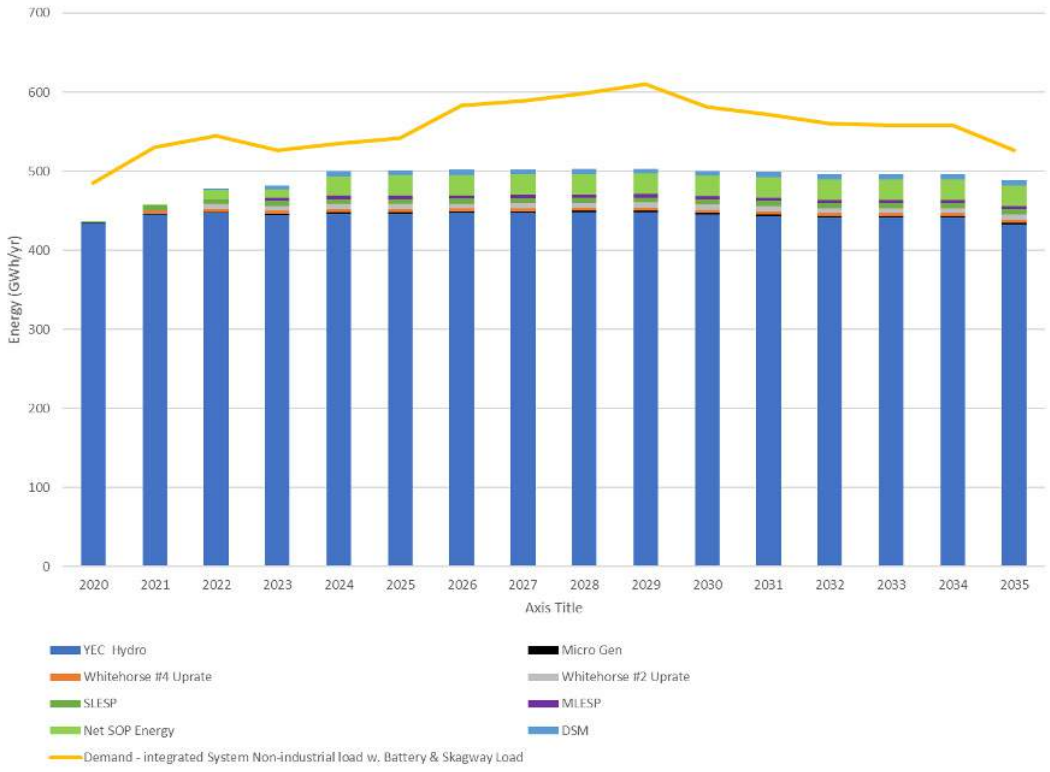


Table B1: Average Annual Energy Surplus/Deficit (Base Case)

YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]	YEAR	AVERAGE ENERGY SURPLUS/(DEFICIT) [GWH]
2020	(49)	2028	(93)
2021	(69)	2029	(103)
2022	(63)	2030	(77)
2023	(42)	2031	(69)
2024	(32)	2032	(60)
2025	(37)	2033	(58)
2026	(78)	2034	(58)
2027	(83)	2035	(35)

Table B2: Average Monthly Energy Gap (Surplus/Deficit)

MONTH	YEAR 2024: AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]	YEAR 2030 (BEFORE SKAGWAY LOAD): AVERAGE ENERGY SURPLUS/ (DEFICIT) [GWH]
Jan	(7)	(4)
Feb	(9)	(5)
Mar	(12)	(6)
Apr	(6)	(2)
May	(1)	0
Jun	4	7
Jul	8	10
Aug	10	11
Sep	8	9
Oct	2	3
Nov	(2)	0
Dec	(5)	(3)
Total Surplus [GWh]:	**32**	**40**
Total Deficit [GWh]:	**(42)**	**(20)**

Table B3: Dependable Capacity Surplus/Deficit under N-1 Conditions (Base Case)

YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]	YEAR	DEPENDABLE CAPACITY SURPLUS/ (DEFICIT) [MW]
2020/21	(26)	2028/29	(32)
2021/22	(26)	2029/30	(37)
2022/23	(20)	2030/31	(42)
2023/24	(14)	2031/32	(44)
2024/25	(17)	2032/33	(46)
2025/26	(20)	2033/34	(46)
2026/27	(24)	2034/35	(48)
2027/28	(28)	2035/36	(50)

Appendix C:
Additional Scenario Portfolio Results

C.1 Base Case (Without Skagway) Portfolio

Figure C1: Base Case (Without Skagway), Energy

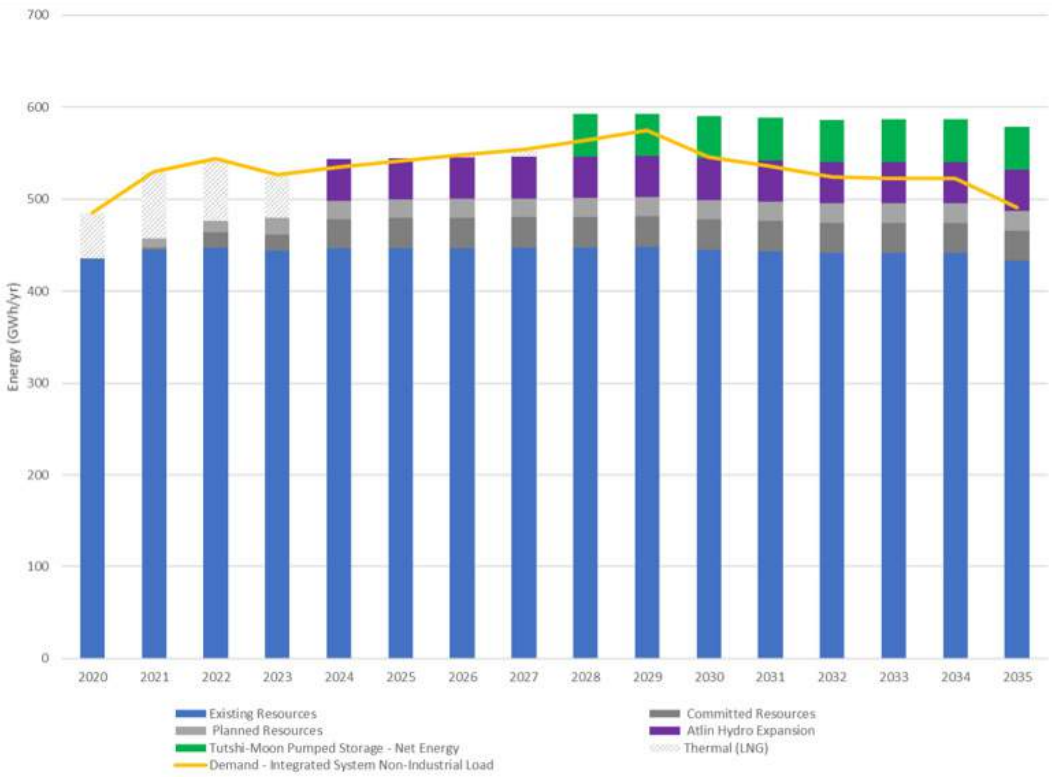


Figure C2: Base Case (Without Skagway), Capacity

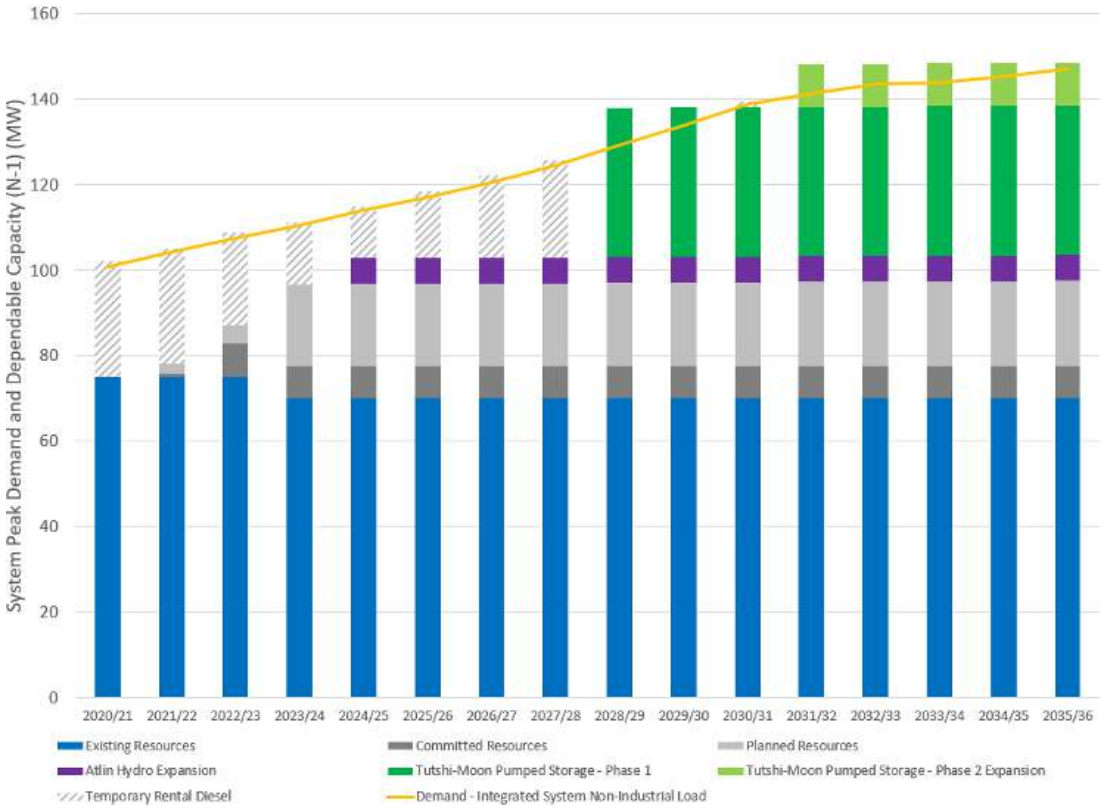


Table C1: Base Case (Without Skagway) Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2024/25 Atlin Hydro Expansion Project	6	6
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**41**	**41**
GRAND TOTAL:	**69.9**	**68.1**

Table C2: Base Case (Without Skagway) Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 519 million
Portfolio Capital Cost with Federal Funding:	$ 130 million

C.2 Low Case Portfolio

Figure C3: Low Case, Energy

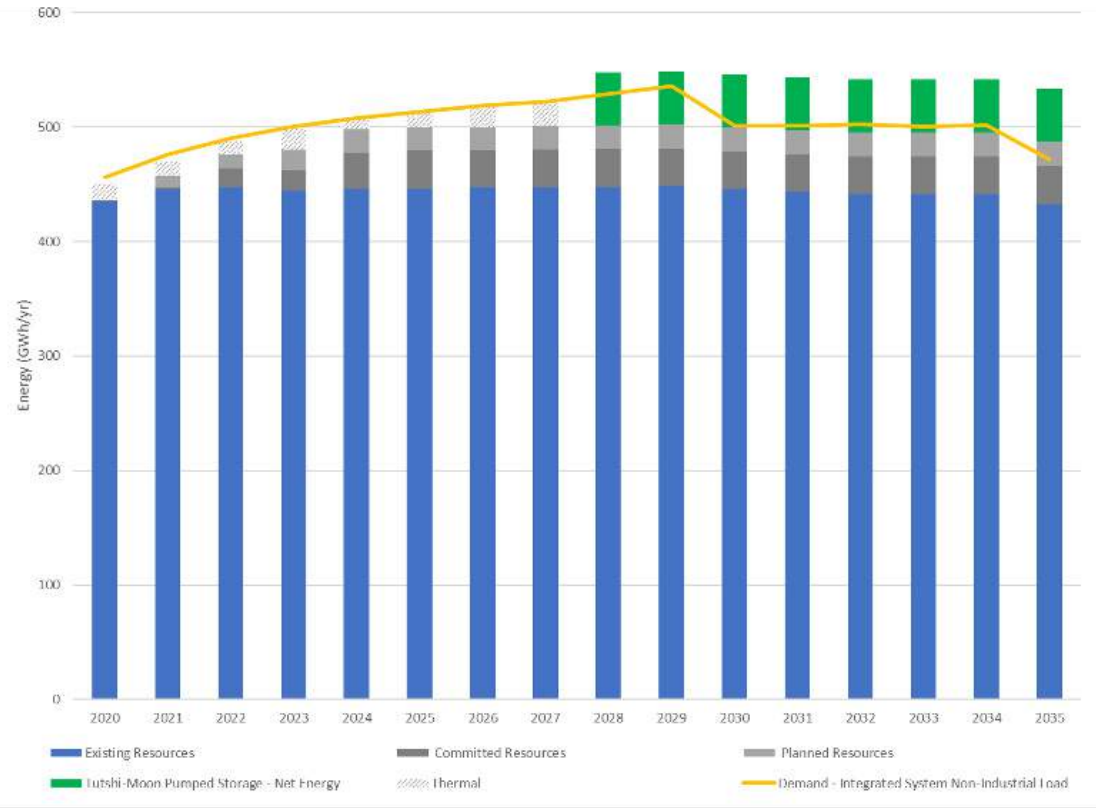


Figure C4: Low Case, Capacity

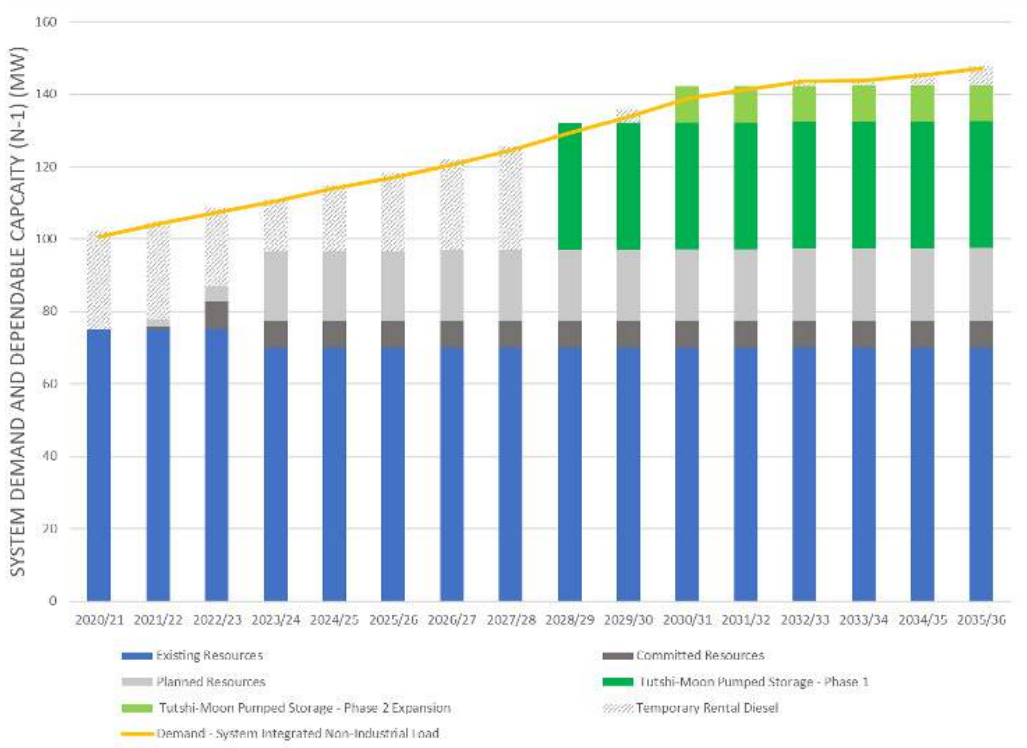


Table C3: Low Case Portfolio Summary (2020 - 2030)

	INSTALLED CAPACITY [MW]	DEPENDABLE CAPACITY [MW]
Committed Resources	8.6	7.6
Planned Resources	20.3	19.5
Sub-total (Committed & Planned)	**28.9**	**27.1**
FUTURE RESOURCES:		
2028/29 Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total (Future Projects):	**35**	**35**
GRAND TOTAL:	**63.9**	**62.1**

Table C4: Low Case Portfolio Cost Summary (2020 - 2030)

COST COMPONENT	COST [2019$ MILLIONS]
Portfolio Capital Cost without Federal Funding:	$ 388 million
Portfolio Capital Cost with Federal Funding:	$ 97 million

Appendix D:
Detailed Scenario Capacity & Capital Costs

D.1 Base Case Portfolio

Table D1: Base Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D2: Base Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 577,000,000**	**$ 432,750,000**	**$ 144,250,000**

[1]The capital costs for the generation projects are from the sources described in Section 7.1.3 and Table 3. The capital costs for the Southern Lakes Transmission Project is based on the 2016 Resource Plan Appendix 5.21: Transmission Options Evaluation study work.

D.2 High Case Portfolio

Table D3: High Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2025/26		
Wind Resource Project	20	0
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	61	41
TOTAL:	**89.9**	**68.1**

Table D4: High Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Wind Resource (20 MW)	$ 73,500,000	$ 55,125,000	$ 18,375,000
Southern Lakes Transmission Project Phase 1-3 (Whitehorse to Skagway)	$ 166,000,000	$ 124,500,000	$ 41,500,000
TOTAL PORTFOLIO:	**$ 650,500,000**	**$ 487,875,000**	**$ 162,625,000**

D.3 Base Case (Without Skagway) Portfolio

Table D5: Base Case (without Skagway) Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2024/25		
Atlin Hydro Expansion Project	6	6
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**41**	**41**
TOTAL:	**69.9**	**68.1**

Table D6: Base Case (without Skagway) Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Atlin Hydro	$ 131,000,000	$ 98,250,000	$ 32,750,000
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 519,000,000**	**$ 389,250,000**	**$ 129,750,000**

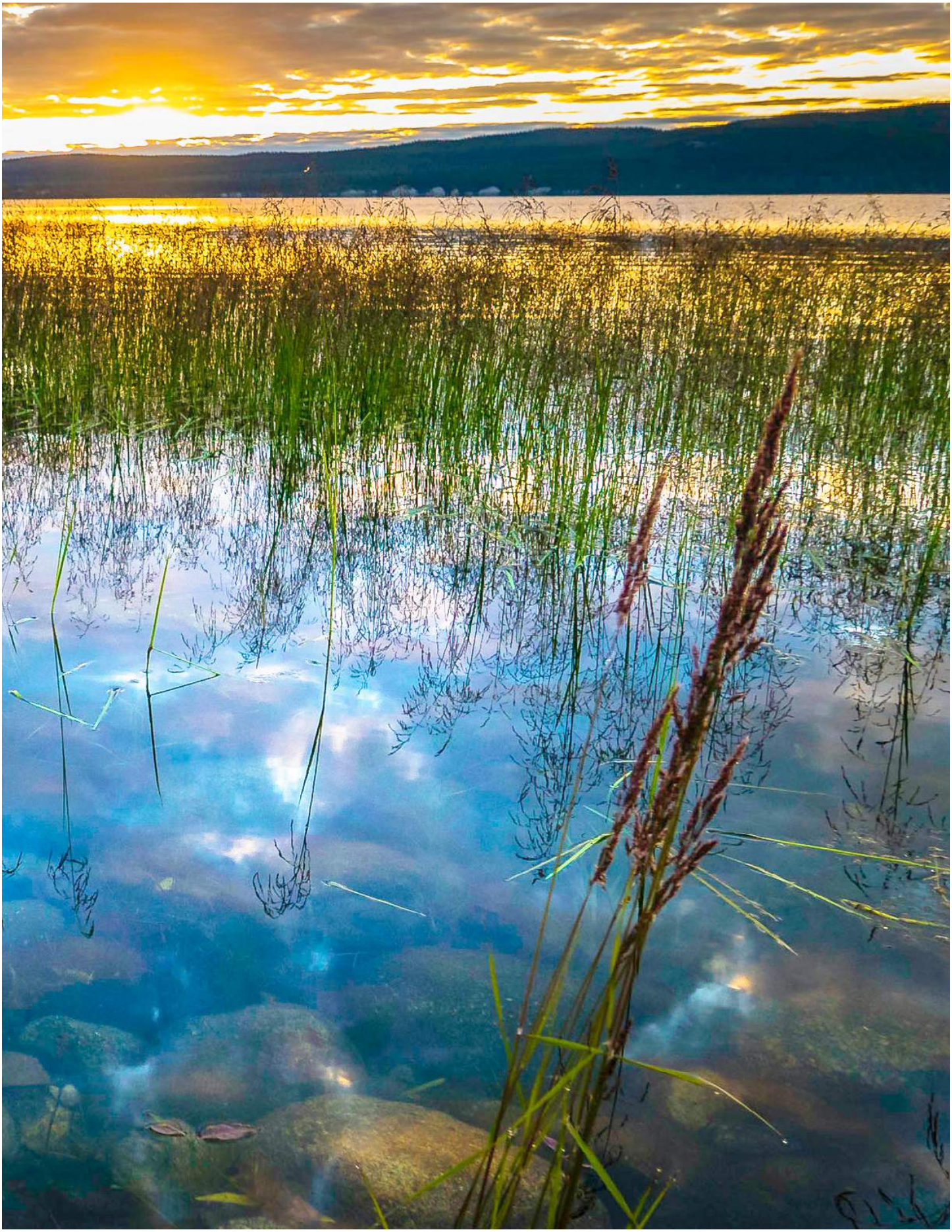
D.4 Low Case Portfolio

Table D7: Low Case Capacity Detail 2020-2030

	Installed Capacity [MW]	Dependable Capacity [MW]
Committed Resources		
Whitehorse #2 Uprate	0.6	0.6
Battery Energy Storage System	8	7
Sub-total:	**8.6**	**7.6**
Planned Resources		
Whitehorse #4 Uprate	0.8	0
Southern Lakes Enhanced Storage	N/A	0
Mayo Lake Enhanced Storage	N/A	0
Incremental Diesel Replacement	12.5	12.5
Demand Side Management	7	7
Sub-total:	**20.3**	**19.5**
Future Projects		
2028/29		
Tutshi-Moon Pumped Storage Project – Phase 1	35	35
Sub-total:	**35**	**35**
TOTAL:	**63.9**	**62.1**

Table D8: Low Case Capital Costs[1] Detail 2020-2030

Cost Component	Capital Cost (2019$)	Federal Funding (2019$)	Total Cost with Federal Funding
Moon Lake Pumped Storage	$ 280,000,000	$ 210,000,000	$ 70,000,000
Southern Lakes Transmission Project Phase 1-2 (Whitehorse to Moon Lake)	$ 108,000,000	$ 81,000,000	$ 27,000,000
TOTAL PORTFOLIO:	**$ 388,000,000**	**$ 291,000,000**	**$ 97,000,000**



Appendix E:
Knight Piesold Hydro Options Report

Prepared for
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Prepared by
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VA103-556/6-1

SMALL HYDROELECTRIC PROJECTS
SCREENING ASSESSMENT (10 MW – 30 MW)

Rev	Description	Date
0	Issued in Final	November 25, 2019

Knight Piésold CONSULTING

EXECUTIVE SUMMARY

Yukon Energy Corporation (YEC) engaged Knight Piésold Ltd. (KP) to update and further develop a desktop review of the potential hydroelectric projects in the Yukon and northern British Columbia. This study builds upon KP's 2016 *Small Hydroelectric Projects Screening Assessment,* the Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study - Site Screening Inventory*, and other historic studies. The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW.

Part I: Screening Assessment

KP completed a screening assessment to progressively eliminate less attractive sites and focus in on the best potential hydroelectric development options. The steps taken in the screening process were:

1. Compilation of a list of 147 sites and alternatives previously considered by Midgard and KP. A handful of additional sites were added for consideration based on proximity to transmission lines and perceived generating potential; however, the review of additional sites should not be considered exhaustive.
2. Screen 1 – Coarse Screening: Projects were grouped by which transmission branch they could be connected to. This included all existing transmission lines in the Yukon as well as a number of proposed lines. With the sites organized, a four-part high-level screen was initiated to eliminate sites that were:
    - Below a 10 MW threshold, or projects not believed to be practical at a 10 MW installed capacity
    - Too distant from transmission (in excess of 50 km from a proposed or existing line)
    - Located in parks (except for Primrose and Tutshi Windy Arm)
    - Affecting the Yukon River or known to flood communities

Sites passing all four of the above criteria, and those sites that were indeterminate on a cursory review, were advanced to Screen 2. A total of 56 sites were advanced.

1. Screen 2 – Quantitative Assessment: KP completed a number of high-level analyses to develop a better understanding of the sites and their hydropower potential. The activities completed in Screen 2 were:
    - Locating sites to best utilize available topographic relief and determining catchment areas
    - Developing conceptual layouts, including intake and powerhouse locations, dam and water conveyance alignments, etc.
    - Reviewing regional hydrological data to establish site-specific estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flow
    - Estimating installed capacity and energy generation profiles
    - Developing indicative capital cost estimates
    - Developing estimates for Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE)

Certain sites appeared to have two or more configuration options. KP reviewed these alternatives at a high-level and selected the best option for presentation in this study. In some instances, a run of river and storage option have both been presented.

1. Screen 3 – Final Screening and Selection of Preferred Sites: the results of Screen 2 were presented to YEC for final consideration and selection of the preferred sites. The final screening criteria were applied as follows:
    - Elimination of those sites associated with the proposed Beaver Creek-Hanes Junction and Faro-Watson Lake transmission lines

- Elimination of sites with dams on major rivers due to social risk and high temporary works construction costs
- Elimination of sites with LCOE values exceeding $0.35/kWh

The preferred sites were determined to be Primrose (storage), Drury (storage), Tutshi-Windy Arm (storage), Wolf (as run of river and storage), and Atlin (storage).

Part II: Concept Development for Preferred Sites

KP completed a closer evaluation of the preferred sites to build upon the quantitative results of the screening process and to provide YEC with the basis for planning future studies for these sites. The table below summarizes the key financial and technical attributes for the five preferred sites.

Further evaluations of the preferred sites are recommended to improve the understanding of engineering, economic, environmental, and social factors impacting project development. The first steps would involve discussions with affected First Nations, acquisition of accurate topography to validate elevations, and the initiation of hydrology studies. Should such evaluations indicate that there are no critical barriers to project development, further evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

Knight Piésold CONSULTING

TABLE 0.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

Print Nov/25/19 08:58:01

DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

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NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR

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APPENDICES

Appendix A Historical Documents and Hydropower Project Sites
Appendix B Site Descriptions

ABBREVIATIONS

C ..... loaded capital cost
CFRD ..... Concrete Faced Rockfill Dam
DFO ..... Fisheries and Oceans Canada
EPCM ..... Engineering, Procurement and Construction Management
GWh ..... gigawatt hour
IFR ..... Instream Flow Requirement
km ..... kilometre
KP ..... Knight Piésold Ltd.
LC ..... levelized capital cost per year
LCOC ..... Levelized Cost of Capacityl=
LCOE ..... Levelized Cost of Energy
m ..... metre
masl ..... metre above sea level
m^3 ..... cubic metre
Mm^3 ..... million cubic metre
m^3/s ..... cubic metre per second
MAD ..... Mean Annual Discharge
MAUD ..... Mean Annual Unit Discharge
MW ..... megawatt
MWh ..... megawatt hour
Q_d ..... design flow
WSC ..... Water Survey of Canada
YDC ..... Yukon Development Corporation
YEC ..... Yukon Energy Corporation
YECL ..... Yukon Electrical Company Ltd.
yr ..... year

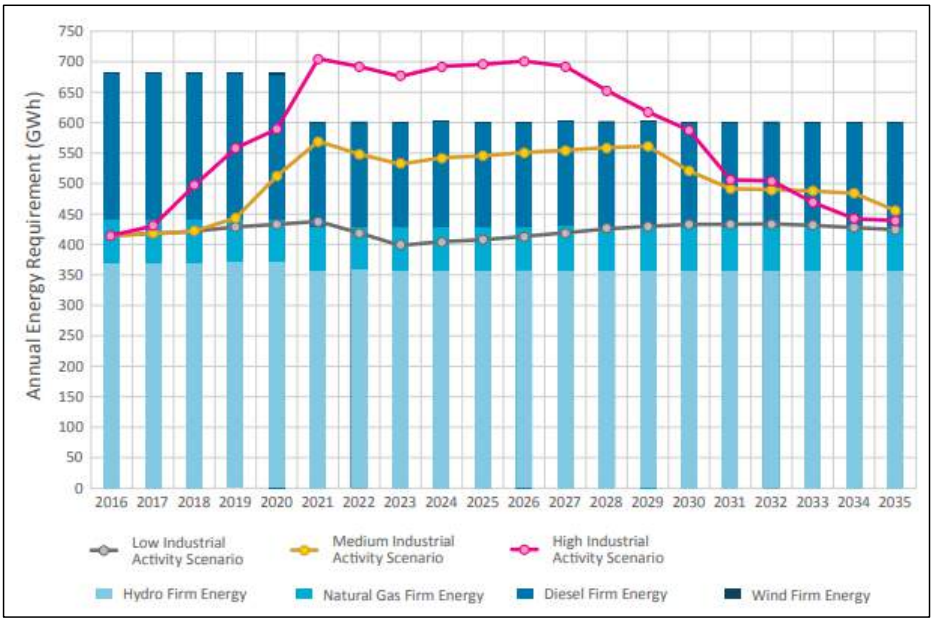
1.0 BACKGROUND

1.1 RESOURCE PLANNING

Yukon Energy Corporation (YEC) and the Yukon government work to ensure that the Yukon's electrical energy needs are met now and in the future, and that future generations can enjoy an energy legacy similar to that provided by the current hydro generation of Whitehorse, Aishihik, Mayo and Fish Lake.

In 2013, the Yukon government issued the Yukon Hydroelectric Power Planning Directive to Yukon Development Corporation (YDC). The directive tasked YDC to plan one or more hydroelectric projects to ensure an adequate and affordable supply of reliable and sustainable electrical power was available in the Yukon.

The 2016 Yukon Energy Resource Plan outlined the energy options that YEC would like to discuss further with the Yukon government, First Nations, stakeholders and the Yukon public. The energy options include small hydro as potential sources of energy to meet future growth. YEC included an investigation of small hydro in its work plan while they monitor how the Yukon load grows over time. Figure 1.1 presents the forecasted energy needs in the Yukon.



NOTES:
1. SOURCE: YUKON ENERGY'S 2016 RESOURCE PLAN (JUNE 2017).

Figure 1.1 Yukon Projected Annual Energy Requirement

The Yukon 2016 Resource Plan states that legally barred and unviable resource options include:

- Generation or transmission options that are located in protected areas or interim protected areas, such as inside a National Park, or projects that would inundate land within a National Park.
- Hydroelectric projects that inundate titled property or a private residence, except for the hydro storage enhancement of existing YEC facilities.
- Projects in remote locations, far from the Yukon transmission grid. The servicing of remote communities is not the focus of the Resource Plan and is covered in specific community planning processes.
- Generation options exceeding 50 MW of installed capacity. Given the YEC demand requirements of the reasonably foreseeable future, and the isolated nature of the Yukon grid, a project beyond this size would exceed domestic requirements, with no ability to sell the surplus.

1.2 ENGAGEMENT

YEC commissioned Knight Piésold Ltd. (KP) in 2019 to update and further develop a desktop review of potential small hydroelectric projects in the Yukon and northern British Columbia. The objectives of the study were to compare technical and economic development criteria and to systematically screen and shortlist development options to provide YEC with the basis to plan future studies on the most attractive sites.

This study is a regional assessment of hydropower development options with capacities between 10 MW and 30 MW, and with estimated transmission line interconnection distances not exceeding 50 km. It builds on KP's 2016 *Small Hydroelectric Projects Screening Assessment*, Midgard Consulting Inc.'s 2015 *Yukon Next Generation Hydro and Transmission Viability Study – Site Screening Inventory*, and other historic studies. It includes a review of all sites previously presented in the 2016 KP study, 2015 Midgard study, and a number of additional sites identified by KP with perceived hydroelectric development potential.

1.3 STUDY LIMITATIONS

The current study is high-level and is based on relatively coarse mapping and hydrology datasets. As such, all results are indicative only and subject to change when better data become available. For example, the publicly available GIS mapping for the Yukon has a contour interval of 20 to 30 metres, and this is restrictive in terms of the identification and evaluation of low-head development sites and low head dams.

The scope of this study is limited to those sites previously identified in the 2016 KP study, the 2015 Midgard study, and a handful of additional sites identified by KP during the current study. There may be other viable sites that have not been considered during previous studies or identified as additional sites in the current study.

The high-level scope and the large number of sites only allowed for limited consideration of alternative configurations at each site. The optimal hydro site will depend on several factors, including capital costs, desired capacity, transmission constraints, environmental impacts, and social conditions.

Finally, the indicative cost estimating performed relies on very generic procedures for estimating quantities (earthworks, concrete, etc.), power equipment types and costs, and transmission line and access road lengths and costs. The values should only be considered as comparative metrics which are used to focus in on the preferred sites. This simplicity is necessary to conduct this type of high-level study, but it may also

lead to oversights in terrain hazards, foundation conditions, or other technical challenges that may affect project costs/viability.

2.0 BACKGROUND INFORMATION

2.1 YUKON POWER GRID

YEC provides the power needs for more than 15,000 customers across the Yukon Territory. The Yukon electricity network is an isolated grid, with no connection to other jurisdictions (i.e. BC, Alaska or Northwest Territory). The Yukon grid currently services all Yukon communities except for Watson Lake, Burwash Landing/Destruction Bay, Beaver Creek, and Old Crow.

2.1.1 CURRENT CAPACITY

YEC currently owns and operates approximately 131 MW of installed capacity, consisting of 92 MW of hydro, 0.8 MW of wind, and 37.8 MW of thermal (diesel and natural gas). Yukon Electrical Company Ltd. (YECL), owned by ATCO, supplies approximately 1.3 MW of hydroelectricity and 6.8 MW of diesel power.

YEC's hydroelectric generating capacity is comprised of:

- 37 MW Aishihik Generating Station, 150 km west of Whitehorse
- 15 MW Mayo Generating Station, 450 km north of Whitehorse
- 40 MW Whitehorse Generating Station, located on the Yukon River at Whitehorse
- 1.3 MW Fish Lake Generating Station (YECL)

2.1.2 EXISTING TRANSMISSION LINES

The Yukon power grid is shown on Figure 2.1 and comprises the following major components:

- 138 kV Whitehorse / Aishihik / Faro (WAF) grid
- 69 kV Mayo / Dawson transmission line
- 138 kV Carmacks / Stewart transmission line, connecting the WAF grid and the Mayo / Dawson transmission line

2.1.3 PROPOSED TRANSMISSION LINES

The following major transmission line extensions have also been considered by YEC:

- Skagway (AK) to Whitehorse through Carcross (YK) and British Columbia
- Atlin (BC) to Whitehorse
- Beaver Creek to Hanes Junction (alternatively Destruction Bay to Hanes Junction)
- Faro to Watson Lake, to connect Watson Lake to the Yukon grid

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

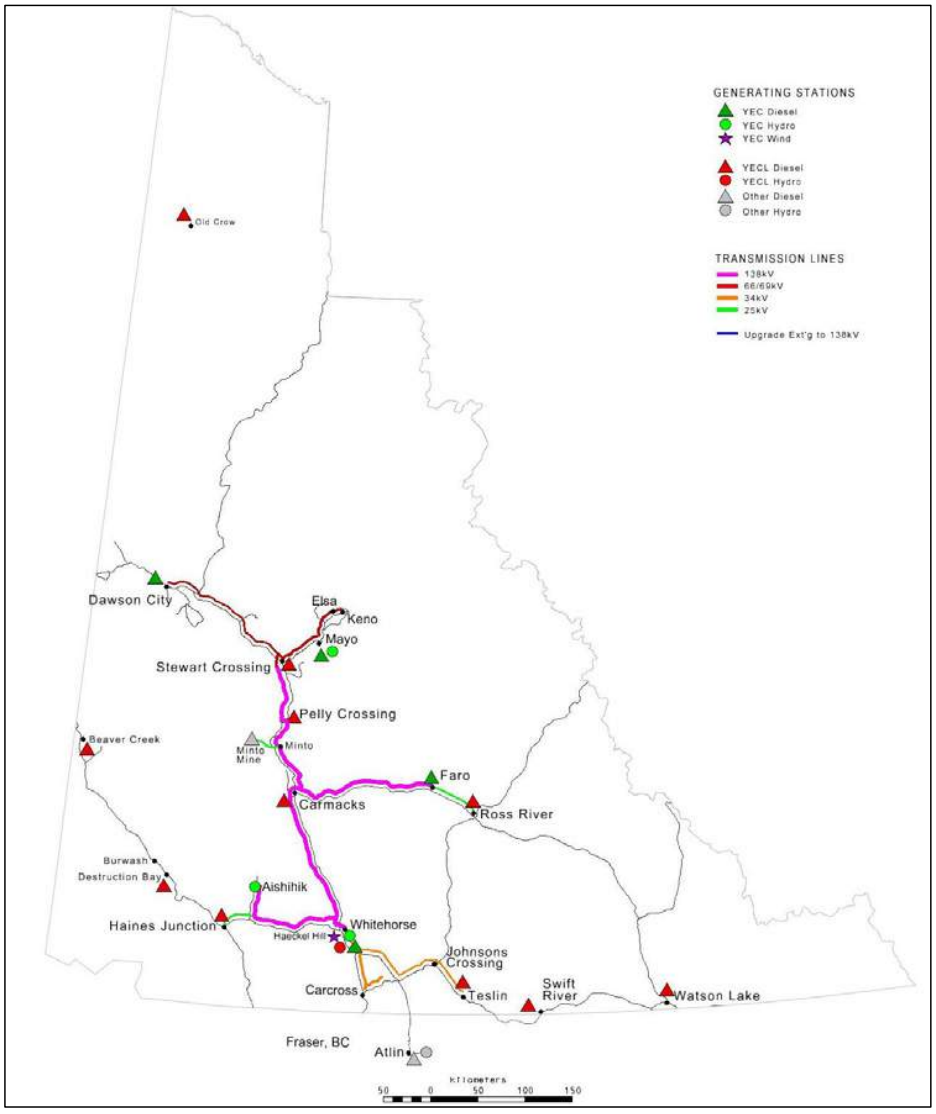


Figure 2.1 Yukon Electricity Network (YEC, 2016)

2.2 OVERVIEW OF HYDROELECTRIC POWER GENERATION

Hydropower is a renewable source of energy with a low carbon footprint. It is a long standing, proven technology that is prevalent worldwide and particularly in regions with high annual precipitation and mountainous terrain.

Conventional hydroelectric power stations can be generally categorized into two types: run of river (RoR) and storage hydro. Storage hydro utilizes water stored behind a dam to generate energy on demand, whereas RoR hydro utilizes the available flows in a river/stream and does not significantly alter natural hydrologic conditions. RoR and Storage hydro are further defined in the sections to follow.

2.2.1 RUN OF RIVER HYDRO

RoR hydroelectric plants utilize the available flow in a river at any given time, with minimal upstream headpond / reservoir live storage. Water is typically diverted at a weir into a water conveyance system (canal, tunnel, and/or penstock), to a powerhouse, and then back into the natural river channel. Very little alteration is made to the natural hydrograph downstream of a run of river project. A conceptual layout of a run of river hydro scheme is provided in Figure 2.2 below.

Electric output is a function of short term (hourly or daily) river discharge, varying daily and seasonally in parallel with the river discharge hydrograph. In the Yukon, run of river generating potential occurs predominantly from May until August, during spring freshet and summer glacial melt.

For the Purpose of this study the run of river projects have been broken down into two categories:

- *"High Head Run of River"* where the projects will divert water away from the main river course, reducing the flow in a portion of the river (i.e. the diversion reach), and then returning the flow to the natural watercourse downstream of the rapids/waterfalls. The project head is generally generated by the natural topographical drop in elevation in the stream over the diversion reach.
- "*Low Head Run of River*" where the project head will principally be generated by the height of the dam/weir in the mainstem of the river. These projects will typically need to handle large flows to generate the required power (i.e. greater than10 MW for the current study). The reservoirs created for these types of dams are not utilized to store the water for electrical generation at select times, but to create the head for power generation. They still operate as run of river facilities utilizing the naturally available flow in the river at any given time.

2.2.2 STORAGE HYDRO

Storage hydroelectric plants utilize an upstream lake or reservoir to store water and to control the outflow and energy output on a daily, monthly, or seasonal basis. This allows for load shaping and winter generation, a times when a run of river hydroelectric facility might not be able to generate a significant amount of energy. A conceptual layout of a storage hydro scheme is provided in Figure 2.2 below.

Storage hydropower configurations vary, from lake/reservoir-controlled High Head RoR style projects, to large dams with built-in generating units where all elevation head is derived from the dam itself, to a combination of both.

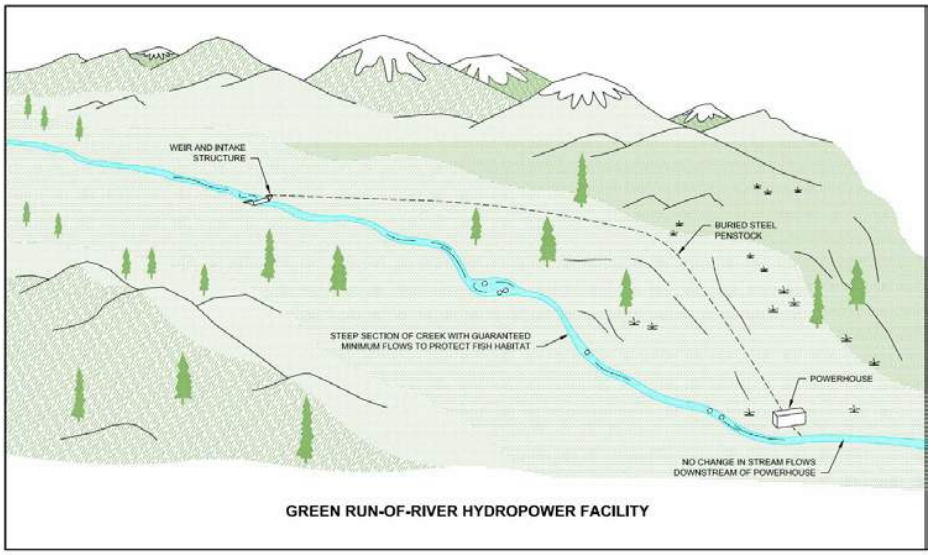


Figure 2.2 Conceptual Hydropower Project Layouts

3.0 SITES AND SCREENING METHODOLOGY

3.1 SITE LIST

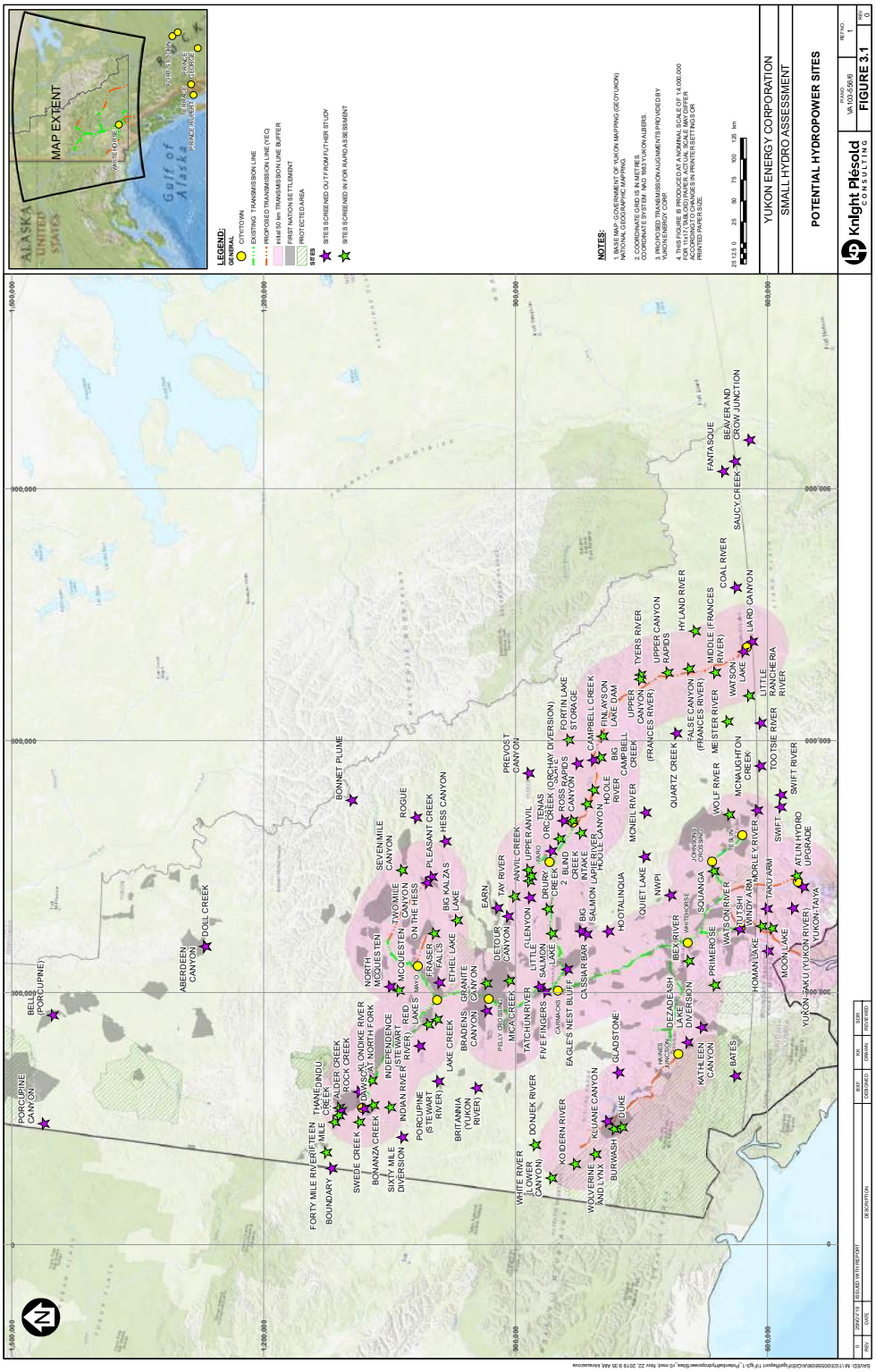
KP compiled a list of 147 sites for preliminary review, comprised of the amalgamated set of sites previously considered in the 2016 KP study and 2015 Midgard study, and a number of additional sites which were identified with perceived hydroelectric development potential in close proximity to transmission lines.

Figure 3.1 shows a map of the Yukon with all sites identified. Table 3.1 provides an alphabetical list of sites.

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

Table 3.1 Site List

Aberdeen Canyon	Fifteen Mile	Lower Canyon on White River	Ross Canyon
Alder Creek	Finlayson	Lynx and Wolverine	Saucy Creek
Anvil Creek	Five Fingers High (150 MW) (Yukon River)	McNaughton Creek	Seven Mile Canyon
Atlin Storage (Yukon River)	Five Fingers High (455 MW) (Yukon River)	McNeil	Site 124
Bates Canyon	Five Fingers Low (75 MW) (Yukon River)	McQuestin	Site 127
Bates Canyon + Dezadeash Diversion	Fortin Lake	Meister River	Sixty Mile River Diversion
Beaver Crow	Forty Mile River	Mica Creek	Slate Rapids (Diversion Scheme)
Bell	Frances River (Lower Canyon)	Middle Canyon (38 MW Version)	Slate Rapids (Powerhouse in Main Dam)
Big Campbell Creek	Frances River (Middle)	Middle Site	Squanga Creek
Big Kalzas Lake	Frances River (Upper Canyon Large)	Moon Lake + Tutshi River Outlet Site A Cluster	Surprise Lake
Big Salmon (Yukon River)	Frances River (Upper Canyon)	Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Swede Creek
Blind Creek	Frances River (Upper Canyon) - At Rapids or at Francis Lake	Moon Lake A	Swift
Bonanza Creek (Grand Forks)	Fraser Falls (High)	Moon Lake B	Swift River
Bonnet Plume	Fraser Falls (Low)	Moon Lake C	Tatshenshini + Dezadeash / Kusawa Diversion
Boundary	Gladstone Diversion	Morley River	Tatshenshini + Dezadeash Diversion
Bradens Canyon	Glenlyon	North Fork Klondike River	Tay River
Bradens Canyon + Fortin Lake Dam	Granite Canyon (Large)	North McQuesten	Tenas Creek (Orchay Diversion)
Britannia (Yukon River)	Granite Canyon (Small)	NWPI (High)	Thane Creek
Burwash	Hess Canyon	NWPI (Low)	Tootsee River
Campbell Creek	Homan Lake	Ogilvie	Tutshi River Outlet Site A (Lake to Lake)
Cassiar Bar (Yukon River)	Hoole Canyon	Orchay	Tutshi River Outlet Site A (Lake to River)
Chandindu River	Hoole Canyon + Fortin Lake Dam	Pleasant Creek	Tutshi River Outlet Site A (River to Lake)
Coal River	Hoole River	Pleasant Creek with Rogue Diversion	Tutshi River Outlet Site A (River to River)
Dawson	Hootalinqua	Porcupine	Tutshi Windy Arm Outlet Site B (East PH)
Detour Canyon	Hyland River	Porcupine Canyon	Tutshi Windy Arm Outlet Site B (West PH)
Detour Canyon + Fortin Lake Dam	Ibex	Prevost Canyon	Two Mile Canyon
Doll Creek	Independence	Primrose Diversion Scheme (To Takhini Lake)	Tyers River
Donjek to White River Diversion	Indian River	Primrose Lake to Takhini Lake Diversion	Upper & Lower Primrose (2008 Layout)
Drury Creek	Kathleen Canyon	Quartz Creek	Upper Canyon on White River
Duke	Kluane Canyon	Quiet Lake Diversion	Watson Lake
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Koidern	Quiet Lake Diversion + Rose River Diversion	Watson River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Lake Creek Diversion	Rancheria	Wind
Eagle's Nest Bluff (Alone) (Yukon River)	Lapie	Reid Lakes and Lake Creek	Wolf River
Earn	Liard Canyon	Rock Creek	Wolverine (Yukon River)
Ethel Lake	Little Rancheria River	Rogue	Yukon-Taiya
False Canyon (Frances River)	Little Salmon Dam	Rose Creek	Yukon-Taku (Yukon River)
Fantasque	Little Salmon Diversion	Rose Lake to Kusawa Lake Diversion	


MAP EXTENT
LEGEND:
GENERAL
CITY/TOWN
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE YEC
FIRST NATION SETTLEMENT
PROTECTED AREA
SITES
SITES SCREENED OUT FROM FURTHER STUDY
SITES SCREENED IN FOR RAPID ASSESSMENT
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. COORDINATE SYSTEM: NAD 1983 YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:4,000,000 ACCORDING TO CONVERSIONS IN PRINTED SET ARCH D PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
POTENTIAL HYDROPOWER SITES
Knight Piésold CONSULTING
FIGURE 3.1

3.2 SCREENING METHODOLOGY

The screening assessment involved several steps to identify, evaluate, and focus in on the preferred hydropower development sites. This process was iterative and included YEC reviews and adjustments to the screening logic throughout the study period. The process was comparable to that used in the 2016 KP study but involved some modifications to the general approach to handle the larger number of sites, modified installed capacity range (between 10 MW and 30 MW), and modified transmission line length restrictions (extended to 50 km).

The process was developed to eliminate sites that are indeterminate, fundamentally flawed, and comparatively expensive or technically unviable, with the overriding objective of providing a focus for future studies on the best development options.

The screening process is described in terms of four main stages:

- Screen 1: Coarse Screening
  - KP applied a coarse screen with four parameters to quickly eliminate many of the less attractive sites which did not warrant an in-depth review. Section 4 describes the coarse screening process.
- Screen 2: Quantitative Assessment
  - KP evaluated a number of quantitative metrics for those sites passing Screen 1 in order to further reduce the site list. Section 5 describes the Screen 2 screening process.
- Screen 3: Final Screening Parameters
  - Those sites passing Screen 2 were presented to YEC for review and feedback, and some final screening criteria were requested by YEC. Section 6 describes the Screen 3 process.
- Assessment of Preferred Options (Top 5 Sites)
  - Screen 3 reduced the site list to the final 5 preferred sites warranting a more detailed assessment. Section 7 describes the final 5 sites.

3.3 DATA COMPILATION

Appendix A summarizes all the previously listed sites and project alternatives in relation to a select number of available reports in which these project sites have been mentioned.

A review of YEC data and a search of publicly available mapping data through the Geomatics Yukon web portal was performed (http://www.geomaticsyukon.ca) to confirm that the data used in the study was as current and comprehensive as possible. In comparison to the 2016 KP study:

- No additional topographical information was available
- Transmission line information was unchanged
- First Nation Settlement Lands were included in the mapping

4.0 SCREEN 1: COARSE SCREENING

4.1 PROJECT GROUPINGS

Projects were first grouped according to the likely transmission line segment (either existing or proposed) that would be used for interconnection. This regional approach helped to streamline the data compilation and review process. The transmission line groupings are:

- Cluster 1: Aishihik-Whitehorse 138 kV (Existing)
- Cluster 2: Carmacks-Whitehorse 138 kV (Existing)
- Cluster 3: Carmacks-Faro 138 kV (Existing)
- Cluster 4: Stewart Crossing-Carmacks 138 kV (Existing)
- Cluster 5: Dawson City-Stewart Crossing 69 kV (Existing)
- Cluster 6: Stewart Crossing-Mayo 69 KV (Existing)
- Cluster 7: Mayo Expansion (Proposed)
- Cluster 8: Faro-Watson Lake (Proposed)
- Cluster 9: Beaver Creek-Hanes Junction (Proposed)
- Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34 kV (Existing)
- Cluster 11: Carcross-Skagway (Proposed)
- Cluster 12: Jake's Corner-Atlin (Proposed)

4.2 SCREENING ASSESSMENT

With the project sites grouped as discussed above, a coarse screening assessment was undertaken to eliminate undesirable sites and allow the more rigorous Screens 2 and 3 to focus on fewer sites. The coarse screen was implemented with four criteria that could be determined on a cursory review:

- 10 MW minimum installed capacity: sites that were unlikely to meet a minimum installed capacity threshold of 10 MW were eliminated.
- 50 km maximum transmission line length: sites more than 50 km from existing or proposed transmission lines were eliminated.
- Parks and protected areas: sites located in parks or restricted areas were eliminated, except for the Primrose and Tutshi Windy Arm sites (on request by YEC).
- Yukon River and communities: sites affecting the Yukon River or known to flood communities were eliminated.

Table 4.1 presents the full list of sites, grouped according to likely interconnection transmission line. Sites which were not eliminated by any of the four coarse screening parameters are shaded in green and represent the 56 sites that advanced to Screen 2. Figure 4.1 shows a map of the Yukon with the sites that advanced to Screen 2.

Knight Piésold CONSULTING

TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Cluster 1: Aishihik-Whitehorse 138 kV (1 of 10)						
Bates Canyon	Pass	Fail	Fail	Pass	No	
Bates Canyon + Dezadeash Diversion	Pass	Fail	Fail	Pass	No	
Gladstone Diversion	NA	NA	Pass	Pass	No	Diversion to Aishihik, Could be looked at further
Kathleen Canyon	Fail	Pass	Pass	Pass	No	
Rose Lake to Kusawa Lake Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash / Kusawa Diversion	Pass	Pass	Fail	Pass	No	
Tatshenshini + Dezadeash Diversion	Pass	Pass	Fail	Pass	No	
Primrose Diversion Scheme (To Takhini Lake)	Pass	Pass	Pass	Pass	No	
Primrose Lake to Takhini Lake Diversion	Pass	Pass	Pass	Pass	No	
Upper & Lower Primrose (2008 Layout)	Pass	Pass	TBD	Pass	Yes	Protected Area
Cluster 2: Carmacks-Whitehorse 138 kV (1 of 5)						
Hootalinqua	Pass	Pass	Pass	Fail	No	
Ibex	TBD	Pass	Pass	Pass	Yes	
NWPI (High)	Pass	Fail	Pass	Pass	No	
NWPI (Low)	Pass	Fail	Pass	Pass	No	
Swift	NA	Fail	Pass	Pass	No	
Cluster 3: Carmacks-Faro 138 kV (5 of 14)						
Big Salmon (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Cassiar Bar (Yukon River)	Pass	Pass	Pass	Fail	No	Assumed location on Yukon River
Detour Canyon	Pass	Fail	Pass	Pass	No	Large System, A Bit far from TL
Detour Canyon + Fortin Lake Dam	Pass	Fail	Pass	Pass	No	TL at 80
Eagle's Nest Bluff (Yukon River) + Rink Rapids (1 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Yukon River) + Rink Rapids (2 PH)	Pass	Pass	Pass	Fail	No	Yukon River
Eagle's Nest Bluff (Alone) (Yukon River)	Pass	Pass	Pass	Fail	No	Yukon River
Earn	Fail	Fail	Pass	Pass	No	Lake capacity can increase but a bit far from TL
Little Salmon Diversion	TBD	Pass	Pass	Pass	No	
Anvil Creek	TBD	Pass	Pass	Pass	Yes	Change location of diversion.
Drury Creek	TBD	Pass	Pass	Pass	Yes	Capacity could be increased to meet the requirement.
Glenlyon	TBD	Pass	Pass	Pass	Yes	
Little Salmon Dam	TBD	Pass	Pass	Pass	Yes	Impact to Camping, Fish Presence
Tay River	TBD	Pass	Pass	Pass	Yes	Actual TL > 50 km
Cluster 4: Stewart Crossing - Carmacks 138 kV (4 of 13)						
Bradens Canyon	Pass	Pass	Pass	Fail	No	
Bradens Canyon + Fortin Lake Dam	Pass	Pass	Pass	Fail	No	
Britannia (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (150 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers High (455 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Five Fingers Low (75 MW) (Yukon River)	Pass	Pass	Pass	Fail	No	
Porcupine	Pass	Pass	Pass	Fail	No	
Wolverine (Yukon River)	Pass	Pass	Pass	Fail	No	
Granite Canyon (Large)	Fail	Pass	Pass	Pass	No	
Granite Canyon (Small)	Pass	Pass	Pass	Pass	Yes	
Lake Creek Diversion	Pass	Pass	Pass	Pass	Yes	
Reid Lakes and Lake Creek	TBD	Pass	Pass	Pass	Yes	
Mica Creek	Pass	Pass	Pass	Pass	Yes	
Cluster 5: Dawson City - Stewart Crossing 69 kV (10 of 16)						
Boundary	Pass	Fail	Pass	Fail	No	
Dawson	Pass	Pass	Pass	Fail	No	
Independence	Pass	Pass	Pass	Fail	No	
Ogilvie	Pass	Fail	Pass	Fail	No	
Rock Creek	Fail	Pass	Pass	Pass	No	
Sixty Mile River Diversion	Pass	Fail	Pass	Pass	No	
Alder Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Bonanza Creek (Grand Forks)	TBD	Pass	Pass	Pass	Yes	ROR TBD
Chandindu River	TBD	Pass	Pass	Pass	Yes	Try ROR
Fifteen Mile	TBD	Pass	Pass	Pass	Yes	ROR TBD
Forty Mile River	Pass	Pass	Pass	Pass	Yes	
Indian River	TBD	Pass	Pass	Pass	Yes	
McQuestin	TBD	Pass	Pass	Pass	Yes	Large System, Cascade
North Fork Klondike River	Pass	Pass	Pass	Pass	Yes	
Swede Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Thane Creek	TBD	Pass	Pass	Pass	Yes	ROR TBD
Cluster 6: Stewart Crossing - Mayo 69 kV (0 of 2)						
Ethel Lake	Fail	Pass	Pass	Pass	No	
North McQuesten	Fail	Pass	Pass	Pass	No	
Cluster 7: Proposed Mayo Transmission Expansions (3 of 9)						
Fraser Falls (Low)	Pass	Pass	Fail	Pass	No	Only one version to be investigated
Hess Canyon	Pass	Fail	Pass	Pass	No	
Pleasant Creek	Fail	Pass	Pass	Pass	No	
Pleasant Creek with Rogue Diversion	Pass	Fail	Pass	Pass	No	
Rogue	Pass	Fail	Pass	Pass	No	Far and Isolated
Two Mile Canyon	Pass	Fail	Pass	Pass	No	
Big Kalzas Lake	Pass	Pass	Pass	Pass	Yes	
Fraser Falls (High)	Pass	Pass	TBD	Pass	Yes	Need to move out of Horshoe Slough Habitat Protection Area
Seven Mile Canyon	Pass	Pass	Pass	Pass	Yes	
Cluster 8: Proposed Faro to Watson Lake (21 of 31)						
Frances River (Upper Canyon Large)	Fail	Pass	Pass	Pass	No	
Frances River (Upper Canyon)	TBD	Pass	Pass	Pass	No	
Middle Canyon (38 MW Version)	TBD	Pass	Pass	Pass	No	No Info
Prevost Canyon	Pass	Fail	Pass	Pass	No	
Rancheria	TBD	Fail	Pass	Pass	No	
Rose Creek	TBD	Pass	Pass	Pass	No	
Slate Rapids (Diversion Scheme)	TBD	Pass	Pass	Pass	No	
Tenas Creek (Orchay Diversion)	TBD	Pass	Pass	Pass	No	
Tootsee River	Fail	Fail	Pass	Pass	No	100 km TL
Watson Lake	Fail	Pass	Pass	Pass	No	

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TABLE 4.1

YUKON ENERGY CORPORATION
REGIONAL HYDROPOWER ASSESSMENT

COARSE SITE SCREENING (56 of 147)

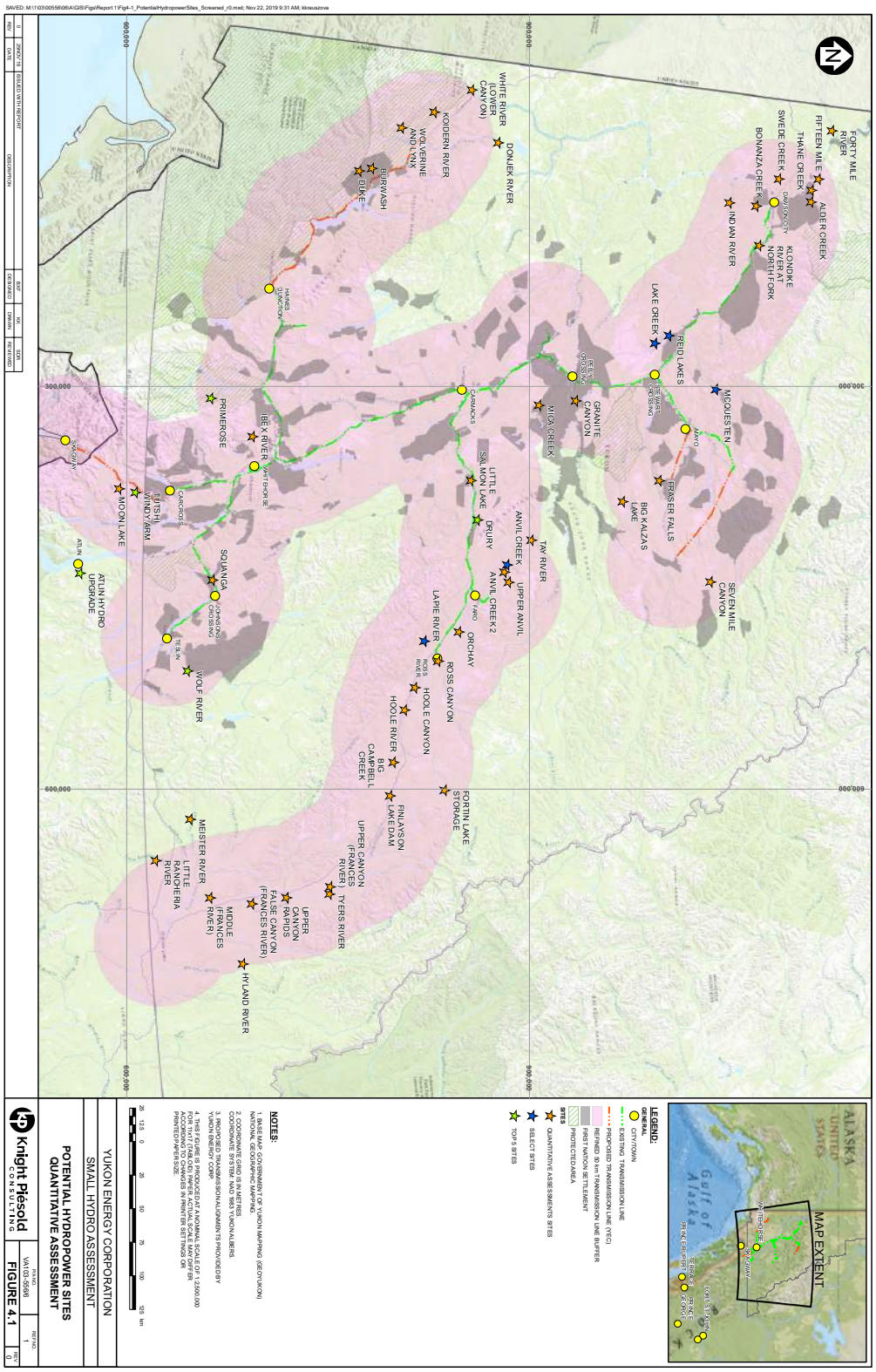
Print: Nov/Mon/19 09:40:30

Site Name	Capacity Screen	T-Line Screen	Park Screen	Flood & Yukon Screen	Include in Rapid Assessment	Notes:
Big Campbell Creek	Pass	Pass	Pass	Pass	Yes	
Blind Creek	TBD	Pass	Pass	Pass	Yes	
Campbell Creek	TBD	Pass	Pass	Pass	Yes	Storage Not Possible, ROR, Mixed with Big Campbell
False Canyon (Frances River)	Pass	Pass	Pass	Pass	Yes	Frances River System
Finlayson	Pass	Pass	Pass	Pass	Yes	
Fortin Lake	TBD	TBD	Pass	Pass	Yes	
Frances River (Lower Canyon)	Pass	Pass	Pass	Pass	Yes	
Frances River (Middle)	Pass	Pass	Pass	Pass	Yes	
Frances River (Upper Canyon)	Pass	Pass	Pass	Pass	Yes	At Rapids or at Francis Lake
Hoole Canyon	Pass	Pass	Pass	Pass	Yes	
Hoole Canyon + Fortin Lake Dam	Pass	Pass	Pass	Pass	Yes	A bit involved, TBD
Hoole River	Pass	Pass	Pass	Pass	Yes	
Hyland River	TBD	TBD	Pass	Pass	Yes	
Lapie	Pass	Pass	Pass	Pass	Yes	Push intake uphill.
Liard Canyon	Pass	Pass	Pass	Pass	Yes	Deemed Urban Flooding - See Note 1.
Little Rancheria River	Pass	Pass	Pass	Pass	Yes	50 km from Watson, 10 MW ROR
Meister River	TBD	Fail	Pass	Pass	Yes	Site of potential but > 50 km TL
Orchay	TBD	Pass	Pass	Pass	Yes	
Ross Canyon	Pass	Pass	Pass	Pass	Yes	
Slate Rapids (Powerhouse in Main Dam)	Pass	Pass	Pass	Pass	Yes	
Tyers River	TBD	Pass	Pass	Pass	Yes	
Cluster 9: Proposed Beaver Creek to Hanes Junction (6 of 8)						
Kluane Canyon	TBD	Pass	Fail	Pass	No	
Upper Canyon on White River	Pass	Pass	Fail	Pass	No	
Burwash	TBD	Pass	TBD	Pass	Yes	
Donjek to White River Diversion	Pass	Pass	Pass	Pass	Yes	
Duke	TBD	Pass	TBD	Pass	Yes	
Koidern	TBD	Pass	TBD	Pass	Yes	
Lower Canyon on White River	Pass	Pass	Pass	Pass	Yes	
Lynx and Wolverine	TBD	Pass	TBD	Pass	Yes	
Cluster 10: Whitehorse-Carcross-Jake's Corner-Johnson's Crossing-Teslin 34kV (2 of 5)						
Morley River	Fail	Pass	Pass	Pass	No	
Swift River	TBD	Fail	Pass	Pass	No	
Watson River	Fail	Pass	Pass	Pass	No	
Squanga Creek	Pass	Pass	Pass	Pass	Yes	Need to Increase Project Head, longer structure (80-100m)
Wolf River	Pass	Pass	Pass	Pass	Yes	
Cluster 11: Proposed Extension from Carcross to Skagway (2 of 13)						
Homan Lake	Fail	Pass	Pass	Pass	No	Increase Project Head, longer structure (80-100m)
Moon Lake A	Fail	Pass	Pass	Pass	No	
Moon Lake C	Fail	Pass	Pass	Pass	No	
Moon Lake B	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (Lake to River)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to Lake)	Fail	Pass	Pass	Pass	No	
Tutshi River Outlet Site A (River to River)	Fail	Pass	Pass	Pass	No	
Tutshi Windy Arm Outlet Site B (West PH)	Fail	Pass	Pass	Pass	No	
Yukon-Taiya	Fail	Pass	Pass	Fail	No	
Moon Lake + Tutshi River Outlet Site A Cluster	Pass	Pass	Pass	Pass	Yes	
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster	Pass	Pass	Pass	Pass	Yes	
Tutshi Windy Arm Outlet Site B (East PH)	Pass	Pass	Pass	Pass	No	Will need to increase installed Capacity
Cluster 12: Proposed Extension from Jake's Corner to Atlin (1 of 3)						
Yukon-Taku (Yukon River)	Pass	Pass	Pass	Fail	No	
Surprise Lake	Pass	Pass	Pass	Pass	Yes	
Atlin Storage (Yukon River)	Pass	Pass	Pass	Fail	No	
Projects too far from Transmission (18)						
Aberdeen Canyon		Fail			No	
Beaver Crow		Fail			No	
Bell		Fail			No	
Bonnet Plume		Fail			No	
Coal River		Fail			No	
Doll Creek		Fail			No	
Fantasque		Fail			No	
McNaughton Creek		Fail			No	
McNeil		Fail			No	
Middle Site		Fail			No	
Porcupine Canyon		Fail			No	
Quartz Creek		Fail			No	
Quiet Lake Diversion		Fail			No	
Quiet Lake Diversion + Rose River Diversion		Fail			No	
Saucy Creek		Fail			No	
Site 124		Fail			No	
Site 127		Fail			No	
Wind		Fail			No	

M:\1\03\00556\06\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\[Table 4.1.xlsx]Coarse Screen

NOTES:
1. MAY WARRANT A CLOSER LOOK DUE TO THE PRESENCE OF RAPIDS AND TOPOGRAPHIC INACCURACIES AT THE BOUNDARY BETWEEN THE YUKON AND BC.
2. SITES HIGHLIGHTED GREEN HAVE PASSED THE INITIAL COARSE SITE SCREENING.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV'19	ISSUED FOR REPORT VA103-556/6-1	BXF	SDR


SAVED: M:\1\03\00556\08\A\GIS\Fig\Report 1\Fig4-1_PotentialHydropowerSites_Screened_r0.mxd; Nov 22, 2019 9:31 AM; kkrauzova
FORTY MILE RIVER
FIFTEEN MILE
ALDER CREEK
THANE CREEK
SWEDE CREEK
DAWSON CITY
BONANZA CREEK
KLONDIKE RIVER AT NORTH FORK
INDIAN RIVER
LAKE CREEK
REID LAKES
MCQUESTEN
SEVEN MILE CANYON
FELIX CREEK
GRANITE CANYON
MTGA CREEK
ANVIL CREEK
TAY RIVER
UPPER ANVIL
FRASER FALLS
BIG KALZAS LAKE
CARMACKS
LITTLE SALMON LAKE
DRURY
ANVIL CREEK 2
FARO
ORCHAY
LAPIE RIVER
ROSS RIVER
ROSS CANYON
HOOLE CANYON
HOOLE RIVER
CAMPBELL CREEK
BIG
FINLAYSON LAKE DAM
FORTIN LAKE STORAGE
UPPER CANYON (FRANCES RIVER)
TY ERS RIVER
UPPER CANYON RAPIDS
FA SE CANYON (FRANCES RIVER)
MIDDLE (FRANCES RIVER)
HY LAND RIVER
MEISTER RIVER
LITTLE RANCHERIA RIVER
WHITE RIVER (LOWER CANYON)
DONJEK RIVER
KOIDERN RIVER
WOLVERINE AND LYNX
BURWASH
DUKE
HAINES JUNCTION
PRIMROSE
IBEX RIVER
WHITEHORSE
CARCROSS
TUTSHI
WINDY ARM
MOON LAKE
ATLIN
ATLIN HYDRO UPGRADE
SQUANGA
CARCROSS/ TAGISH ROAD
TESLIN
WOLF RIVER
LEGEND:
GENERAL
CITY/TOWN
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
REFINED 30 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
SITES
QUANTITATIVE ASSESSMENTS SITES
SELECT SITES
TOP 5 SITES
MAP EXTENT
ALASKA
UNITED STATES
Gulf of Alaska
WHITEHORSE
TESLIN
WATSON LAKE
FORT ST. JOHN
PRINCE GEORGE
PRINCE RUPERT
NOTES:
1. BASEMAP CONTRIBUTIONS OF YUKON MAPPING (GEOYUKON)
NATIONAL GEOGRAPHIC MAPPING
2. COORDINATE GRID IS IN METRES
COORDINATE SYSTEM: NAD 1983 YUKON ALBERS
3. PROVIDED TRANSMISSION ALIGNMENTS PROVIDED BY
YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,500,000
FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER
ACCORDING TO CHANGES IN PRINTER SETTINGS OR
PRINTED PAPER SIZE.
0 12.5 25 50 75 100 125 km
Knight Piésold CONSULTING
PA NO. VA110-00/8
REF NO. 1
REV. 0
FIGURE 4.1
POTENTIAL HYDROPOWER SITES
QUANTITATIVE ASSESSMENT
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
REV. 0
DATE 25NOV19
ISSUED WITH REPORT
DESCRIPTION
ORIGINATED BMF
CHKD'D MK
REVIEWED SGK

5.0 SCREEN 2: QUANTITATIVE ASSESSMENT

5.1 OVERVIEW

Screen 1 reduced the site list from 147 to 56 sites. Those sites passing Screen 1 were subjected to the Screen 2 process, referred to as the 'Quantitative Assessment'. Screen 2 involved a number of analyses:

- Review of existing information and development of a high-level conceptualization of the projects, including intake and powerhouse location, project head, and potential for reservoir storage.
- Regional hydrological review to develop estimates for Mean Annual Discharge (MAD) and the seasonal distribution of flows.
- Estimation of installed capacity and energy generation profiles.
- Indicative cost estimating.
- Levelized financial comparison, including Levelized Cost of Capacity (LCOC) and Levelized Cost of Energy (LCOE).

The subsequent sections of this report detail the components of the Screen 2 process. A summary of the results can be found in Table 5.2, and details of the review and concept development are presented in Appendix B.

5.2 HYDROLOGY AND DESIGN FLOW ESTIMATES

5.2.1 PREVIOUS ESTIMATES

During the 2016 KP study, flow records were compiled and reviewed from a total of 46 Water Survey of Canada (WSC) gauges with catchment areas between 10 km^2 and 7,000 km^2. This analysis was undertaken to develop an understanding of regional trends in measured runoff for catchments of varying sizes and regions. Monthly average data was used to develop estimates of Mean Annual Discharge (MAD) and Mean Annual Unit Discharge (MAUD) at each stream gauge location. The data were then used to produce generic monthly hydrographs which were scaled and applied to each project site.

1. GAUGES IN YUKON.

Figure 5.1 illustrates the "generic" Yukon hydrographs that were developed. Figure 5.2 illustrates the location of Yukon stream gauges along with indicative unit runoffs.

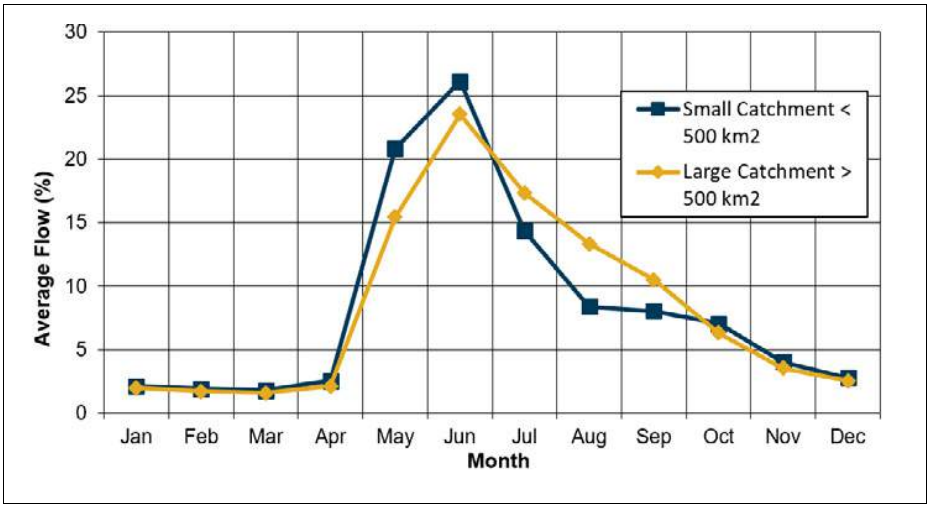
Where no previous hydrology information could be obtained, KP developed estimates based on the MAUD values from the WSC gauges in the region and scaled according to catchment area. These gauges are dispersed across most of the Yukon and provide a reasonable means of assessing hydrologic patterns throughout the region. Some of the basic trends evident in the data are as follows:

- MAUD appears to decrease in a south-westerly direction along the border between the Yukon and the Northwest Territories, with lower unit discharge values evident in the dry, lower relief interior zones versus the mountainous terrain along the eastern provincial border.
- In the south-western corner of the Yukon, MAUD appears to be relatively high due to the onshore movement of moist maritime air from the Pacific Coast. The effects of this moisture influx extend slightly beyond the Coastal Mountain Range, and then drops off markedly due to a 'precipitation shadow' effect that results in a progressive reduction in MAUD moving east.

MAUD values were selected for the project sites based on proximity and similarity of catchment size to the WSC stations. Commonly, there are two to three local gauge stations that provide a basis for estimating unit discharge. Where applicable, consideration was also given to the MAUD values reported for various project sites.

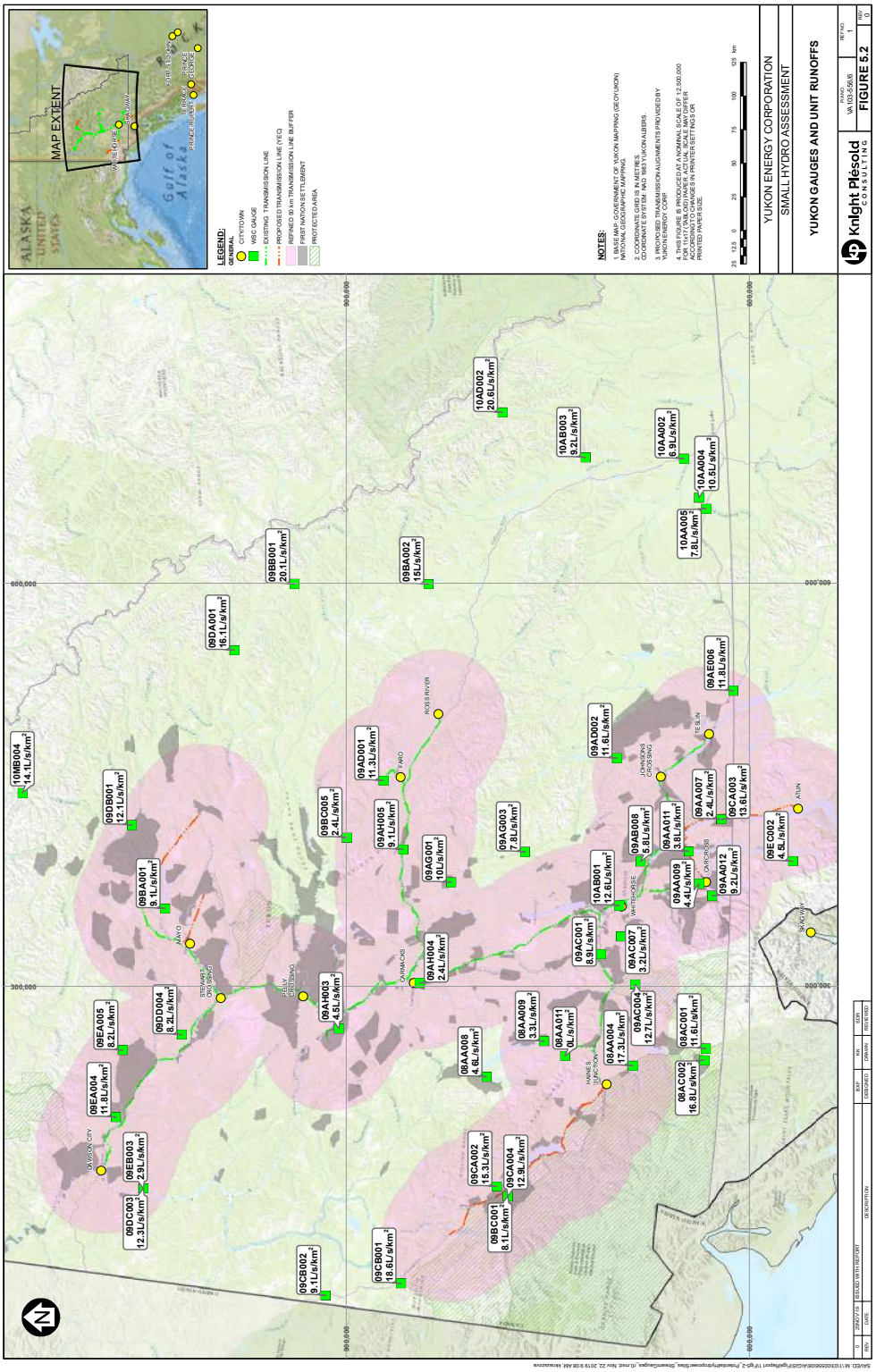
Additional regional considerations when determining a site's MAUD included:

- Glaciers in a watershed, which generally increase MAUD due to melt during the warm summer months
- Lakes in a watershed, which generally decrease MAUD due to greater evaporation
- The local relief, with higher elevation watersheds generally having higher precipitation and correspondingly higher MAUD



NOTES:
2. BASED ON AN EVALUATION OF MONTHLY AVERAGE FLOWS AT 46 WATER SURVEY OF CANADA (WSC) GAUGES IN YUKON.

Figure 5.1 Typical Yukon Hydrograph


MAP EXTENT
ALASKA
UNITED STATES
Gulf of Alaska
WHITEHORSE
DAWSON
HAINES JUNCTION
SKAGWAY
CARCROSS
CARMACKS
PELLY CROSSING
STEWART CROSSING
MAYO
KENO
ROSS RIVER
FARO
JOHNSONS CROSSING
WATSON LAKE
ATLIN
LEGEND:
GENERAL
CITY/TOWN
WSC GAUGE
EXISTING TRANSMISSION LINE
PROPOSED TRANSMISSION LINE (YEC)
REFINED 50 km TRANSMISSION LINE BUFFER
FIRST NATION SETTLEMENT
PROTECTED AREA
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON MAPPING (GEOYUKON) NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES. PROJECTION: ALBERS EQUAL AREA YUKON ALBERS.
3. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
4. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:2,500,000 ACCORDINGLY, DISTANCES AND AREAS MEASURED ON THE SCREEN OR PRINTED PAPER WILL DIFFER FROM THOSE CALCULATED IN PROJECTED GIS DATA.
25 12.5 0 25 50 75 100 125 km
Knight Piésold CONSULTING
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
YUKON GAUGES AND UNIT RUNOFFS
FIGURE 5.2
10MB004 14.1L/s/km²
09DB001 12.1L/s/km²
09BA001 9.1L/s/km²
09DD004 8.2L/s/km²
09EA005 8.2L/s/km²
09EA004 11.8L/s/km²
09EB003 2.9L/s/km²
09DC003 12.3L/s/km²
09CB002 9.1L/s/km²
09CB001 18.6L/s/km²
09BC001 8.1L/s/km²
09CA002 15.3L/s/km²
09CA004 12.8L/s/km²
09AA008 4.6L/s/km²
09AA009 3.3L/s/km²
09AA011 0L/s/km²
09AA004 17.3L/s/km²
09AC004 12.7L/s/km²
09AC001 11.6L/s/km²
08AC002 16.8L/s/km²
09AH003 4.5L/s/km²
09AH004 2.4L/s/km²
09AH005 9.1L/s/km²
09AD001 11.3L/s/km²
09BC005 2.4L/s/km²
09DA001 16.1L/s/km²
09BB001 20.1L/s/km²
09BA002 15L/s/km²
09AG001 10L/s/km²
09AG003 7.8L/s/km²
09AC001 8.9L/s/km²
10AB001 12.2L/s/km²
09AC007 3.2L/s/km²
09AB008 5.8L/s/km²
09AA011 3.8L/s/km²
09AA009 4.4L/s/km²
09AA012 9.2L/s/km²
09AA007 2.4L/s/km²
09CA003 13.6L/s/km²
09EC002 4.5L/s/km²
09AE006 11.8L/s/km²
09AD002 11.6L/s/km²
10AD002 20.6L/s/km²
10AB003 9.2L/s/km²
10AA002 6.9L/s/km²
10AA004 10.5L/s/km²
10AA005 7.8L/s/km²

5.2.2 RUN OF RIVER PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

RoR hydroelectric plants utilize the available flow in a river at any given time, with unusable headpond/reservoir storage, and electric output is a function of short-term yield (often evaluated on a daily basis). The optimal installed capacity depends on numerous factors, including constructability, environmental requirements, and the need for and ability to sell seasonal power.

In the previous KP evaluation most of the run-of-river projects evaluated were of the “high-head type”. Based on experience evaluating these types of projects KP made the assumption that the optimal design flow for a run of river plant tends to be in the order of 1.5 to 2 times the MAD value. In contrast KP targeted a design factor 0.5 times MAD for “low-head” storage type projects on large river systems.

In the current evaluation the study aims to target a specific range of capacity and needed the ability to evaluate run-of-river projects located on large river systems. To accomplish this, curves were developed based on a set of assumptions that showed the exchange of capacity factor as a function of the design flow factor. The design flow for the plant is equal to the design factor times the average annual flow. To develop these curves, daily stream flow data for various streams were downloaded from the WSC, with years having incomplete daily records removed. An energy model was then built for a single unit meter of head based on the following assumptions:

- In-stream Flow Requirements (IFR) equal to 5 percent of MAD
- A minimum turbinable flow of 5% of the design flow
- 10 percent head losses through intake and conveyance to the turbine, at maximum design flow, and an exponential decrease in head loss with decreasing flow
- Average efficiency of 90 percent from turbine to the point of sale, to account for turbine – generator losses, transformer losses, transmission losses, station usage, and outages

For a given design flow factor and project head, the resulting design flow, power and energy can be calculated (see Figure 5.3).

To further assess the winter capacity a similar set of curves was developed, combining the energy generated in the months of December, January, February, and March (see Figure 5.4).

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

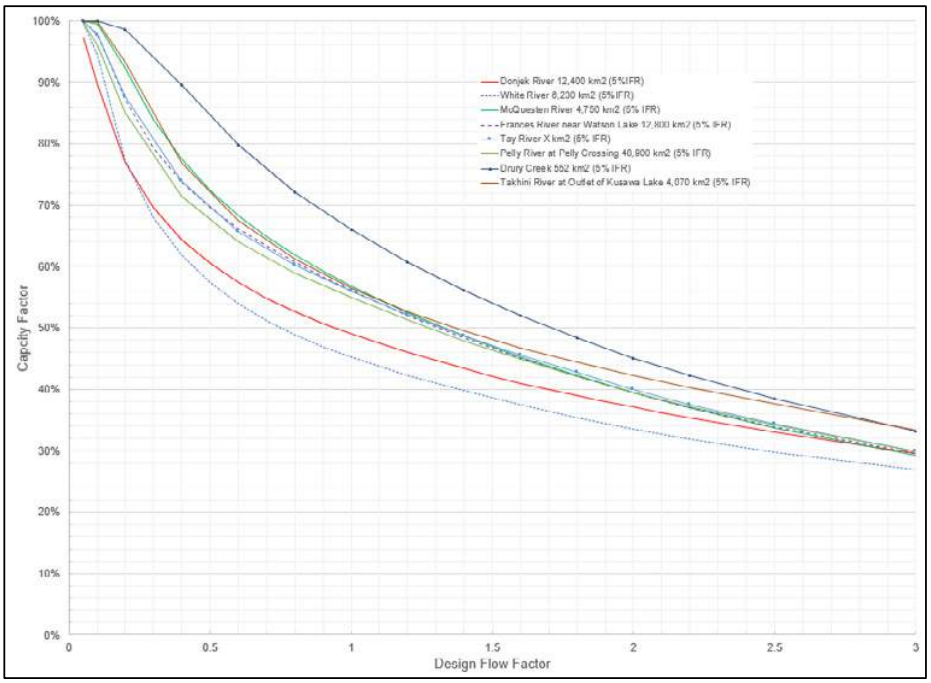


Figure 5.3 **Run of River Based Capacity Factors resulting from Design Flow Factors**

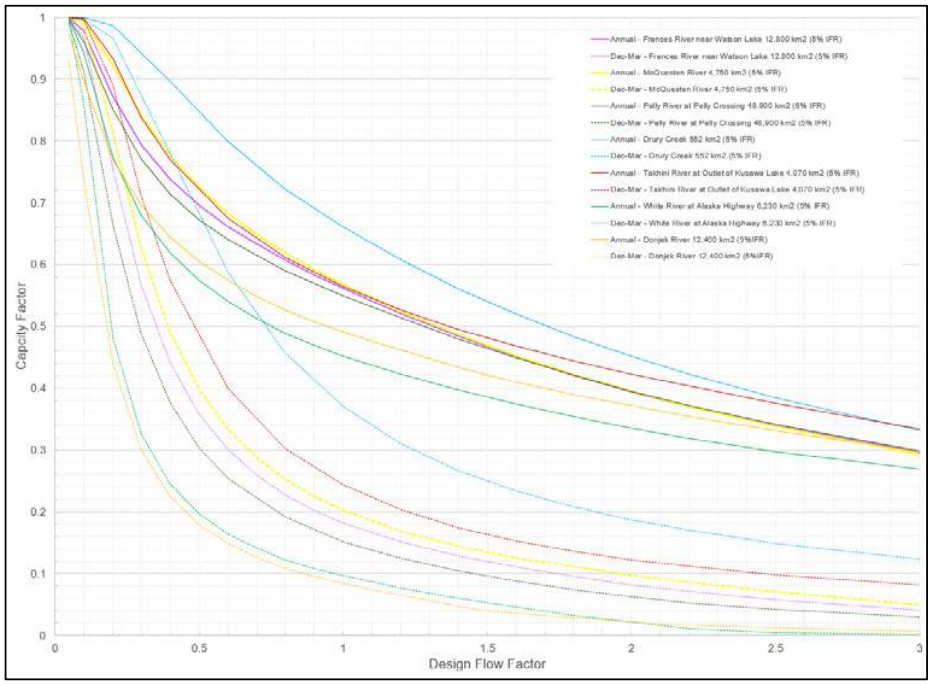


Figure 5.4 **Run of River Based Winter Capacity Factors resulting from Design Flow Factors**

5.2.3 STORAGE PROJECTS DESIGN FLOW FACTORS AND DESIGN FLOWS

Estimating the design flow factor to be applied in energy modeling for a storage hydroelectric project is inherently more complex than for run-of-river analyses. These complexities lie in the regulation of flows due to the ability to store some volume of water for generation. Individual daily storage regulation models were developed for storage sites making the following assumptions:

- Daily inflows were typically prorated from the nearest stream to the proper unit runoff and drainage area (See Table 5.1).
- Depth capacity curves were assumed to be linear between available topographic contours. This was deemed to be acceptable as, in most instances, the reservoir elevation variations were relatively small.
- Release rules assumed a full day release if water was available in the reservoir during the months of December, January, February or March or if the reservoir volume exceeded 90 percent of its capacity.

All other assumptions were identical to the run-of-river model.

Table 5.1 WSC Gauges for Storage Models

Sites	Surrogate Gauge	Complete Record Period
Drury, Big Kalzas, Finlayson, Glenlyon, Reid Lake (Lake Creek)	Drury Creek (09AH005)	1995-2009 and 2016-2017
Fortin	Pelly River at Pelly Crossing (09BC001)	1960-2017
Wolf River	Nisutlin River (09AD001)	1979-1995
Tushi Windy Arm, Primrose	Takhini River (09AC004)	1954,1959-60, 1965-67, 1969-86

5.2.4 DEPENDABLE CAPACITY

YEC requested that all projects shortlisted during this screening process be assessed for Dependable Capacity. Dependable Capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history. Dependable Capacity was only evaluated for the five preferred sites which are discussed in Section 7.

5.3 INDICATIVE COSTS

Basic indicative cost estimates in $2019 were developed for each project using KP's in-house experience and cost estimating database for projects with comparable characteristics. Where the level of detail in the existing design was insufficient to permit an accurate assessment of site-specific conditions, facility layouts and sizes, costs were scaled according to head, flow, installed capacity, and other key project costing metrics. Cost estimates included the following major components:

- Mobilization, Demobilization, Insurance, Bonds, Overheads, and Contractor's Profits
- Access and Site Preparation
- Dam(s) and Reservoir(s) (if any)

- Intake, Forebay, and Headrace
- Water Conveyance System
- Powerhouse and Tailrace and Ancillary Services
- Power Generation Equipment (Water to Wire)
- Switchyard, Transmission, and Interconnection
- Engineering, Procurement, and Construction Management (EPCM): 8 %
- Contingency: 30 %

5.4 COST TO BENEFIT ANALYSIS

The fair evaluation of alternative hydropower development options requires an assessment of project costs and benefits. The cost to benefit assessment was based on the comparative values for the following financial metrics:

- Unit Cost of Capacity (UCC)
- Unit Cost of Energy (UCE)
- Levelized Cost of Capacity (LCOC)
- Levelized Cost of Energy (LCOE)
- Levelized Cost of Winter Energy (LCOWE)

5.4.1 UNIT COST OF CAPACITY

Unit Cost of Capacity = Capital Cost ($) / Installed Capacity (MW)

This unit of measurement can be useful for gauging project costs in relation to other proposed or existing power projects in a simplistic manner. For instance, YEC's Mayo B Hydroelectric Project was constructed for a cost of roughly $120 million and added 10 MW of power to the Yukon's energy system (YEC, 2016), equating to a UCC of $12 million/MW. The LCOC of the better options in this study are in this order of magnitude, providing some confidence in the underlying quantities and unit rates that have been assumed.

While UCC does have its usefulness, it is not a good measure of the overall project value since capacity is not directly correlated to energy production and revenues.

5.4.2 UNIT COST OF ENERGY

Unit Cost of Energy = Capital Cost ($) / Average Annual Energy Production (GWh/yr).

UCE is a simple and useful financial metric for the determination of a project's value and relative ranking of sites with different installed capacities and hydrology characteristics. Provided that all energy can be sold, UCE is directly correlated with revenue.

UCE in the order of $2.5 million/GWh/yr or less are considered to have development potential.

5.4.3 LEVELIZED COST OF CAPACITY

The loaded capital cost, or net present cost at Commercial Operation Date (COD) is accounts interest accrued during construction, using the following formula:

$$LCOC = \frac{levelized\ cost\ of\ capital + annual\ expenditure}{installed\ capacity}$$

The levelized capital cost per year is calculated using the capital recovery factor formula:

$$LC = \frac{rC(1+r)^n}{(1+r)^n - 1}$$

Where:

LC	levelized capital cost per year
C	Capital Cost
O	Operating and maintenance cost (estimated at 2.2% of Capital Costs + $0.005/kWh)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.4 LEVELIZED COST OF ENERGY

In the energy sector, LCOE is often used as a metric for evaluating energy projects because it allows for an “apples-to-apples” comparison of the costs associated with the generation of energy between different energy sources. For instance, there is a desire to be able to fairly compare hydropower projects with high upfront capital costs, and comparably low operations and maintenance costs (i.e. no fuel cost) with, for instance, thermal generation projects with lower upfront capital costs but relatively high operating costs that include fuel consumption.

The hydroelectric LCOE can be compared against the LCOE of a Yukon based thermal generation asset. If the hydroelectric project’s LCOE is higher than the thermal generation LCOE, it is deemed uneconomic.

YEC provided the following information to assist in the hydropower screening evaluation:

- Discount rate for net present valuation: 4.82%
- Yukon grid power: $0.19/kWh
- Diesel generation: $0.33/kWh
- Liquified natural gas (LNG): $0.15/kWh

In order to calculate the LCOE an estimate of the capital and operations and maintenance costs is required. The calculation for LCOE is presented below.

$$LCOE = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ energy\ produced\ over\ lifetime}$$

$$LCOE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t

Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005/kWh)
Et	Energy Generated in year t (estimated to be the mean annual energy)
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.4.5 LEVELIZED COST OF WINTER ENERGY (LCOWE)

For the purpose of this study the Levelized Cost of Winter Energy (LCOWE) was calculated as follows to compare the winter generation portfolios:

$$LCOWE = \frac{\sum_{t=0}^{n} \frac{C^t + O^t - R^t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{WE_t}{(1+r)^t}}$$

Where:

Ct	Capital Cost in year t
Ot	Operating and maintenance cost in year t (estimated at 2.2% of Capital Costs + $0.005kWh)
Rt	Revenue from non winter energy at the Yukon grid power rate of $0.19/kWh
WEt	Energy Generated in December, January, February and March of year t
r	discount rate (assumed 4.82%)
n	expected lifetime of plan + construction period (assuming 3 years of construction and a 65-year design life.)

5.5 SCREEN 2 RESULTS

The results of the Screen 2 assessment are presented in Table 5.2. Additional information regarding the background review and development of concepts is presented in Appendix B.

Knight Piésold CONSULTING

TABLE 5.2

YUKON ENERGY CORPORATION
YUKON REGIONAL POWER ASSESSMENT

HYDROPOWER POTENTIAL ASSESSMENT (10 MW – 30 MW)
QUANTITATIVE ASSESSMENT PROJECT DATA SUMMARY (56 SITES + 5 ALTERNATIVES)

Project Name	Evaluated as	Intake Elev.	Tailwater El. (TWL)	Gross Head	Conveyance Length	Transmission Line	Unit Runoff	Drainage Area	MAD	Design Factor	Design Flow	Installed Capacity	Dam Height	Average Capacity Factor	Average Annual Energy	Average Dec Mean Energy	Capital Cost	Capital Cost to Capacity	Capital Cost to Energy	LCOC	LCOE	Screened Out Due to Undiscovered Cultural Concern	Screened Out Due to Proximity to Cluster Location	Screened Out Due to Proximity to Cluster Perceived Social Risk	Screened Out, Due to Cost	Reviewed for Final Selection	Comments
		masl	masl	m	m	km	l/s/km²	km²	m³/s		m³/s	MW	m	%	GWh/a	GWh/a	M$	M$/MW	M$/GWh/a	$/kWh-dry	$/kWh @ 4.0%						
Primrose River*	HH ROR	**Storage**	878	710	168	4,700	39	12.7	1,139	14.5	0.8	11.6	25	70%	777.2	34.7	190	14.9	2.28	1.377	0.175					Yes	Barrier Access to Protected Area
Toe River	HH ROR	Storage	625	540	85	5,000	20	12.5	323	4.0	2	8.1	11	50%	47.9	2.1	110	14.0	2.29	2.220	0.660	X				No	
													Cluster 2: Cassiar to Whitehorse 138 kV (1 of 5 Alternatives)														
Anvil Creek	HH ROR		905	625	280	8,000	28	8.0	557	2.0	1.7	0.5	21.4	38%	62.0	4.8	340	14.6	4.15	1.376	0.315					Yes	Tunnel
Drury Creek*	HH ROR	Storage	1,100	730	370	5,300	1	5.3	1,109	14.5	0.8	11.6	25	70%	777.2	34.7	190	14.9	2.28	1.377	0.175					Yes	
Grayrock	HH ROR	Storage	730	630	100	5,200	1	8.1	838	4.9	1.0	8.6	25	38%	31.9	2.5	116	11.1	3.63	2.248	0.648					Yes	
Little Rancheria	Storage	Tay River	810	540	270	8,600	10	8.6	2,581	23.4	2.0	16.3	30	50%	71.5	6.5	320	19.6	4.92	3.557	1.052			X		No	Recreational Areas
Tay River	HH ROR		653	540	80	10,000	20	2.4	11,443	27.5	1.0	22.5	118	50%	517.5	6.5	320	29.6	4.92	2.053	0.1921				X	No	
													Cluster 3: Stewart Crossing to Whitehorse 138 kV (1 of 3 Alternatives)													
Lake Creek	HH ROR		600	540	60	6200	15	10	1015	10.2	2.00	20.3	129	40%	451.0	33.5	170	13.4	3.82	1.300	0.289					Yes	
Red Lakes (Fuller Creek)	Storage		510	480	30	3700	5	10	1,109	11.1	2.00	22.2	106	49%	417.7	16.3	140	13.5	3.44	1.196	0.261		X			No	Can only be developed with Lake Creek
Mica Creek	HH ROR		540	540	0	8000	2	6.5	1,291	14.4	2.00	12.91	41	40%	144.1	1.2	200	48.4	13.91	3.000	1.038	X				No	
													Cluster 5: Dawson City - Stewart Crossing 69 kV (2 of 10)													
Alaska Creek	HH ROR		400	340	60	2300	1	2.8	236	1.2	2.00	2.4	19	38%	6.4	0.1	80	41.7	10.49	4.742	1.634	X	X			No	
Chandindu River	HH ROR		375	340	35	8000	1	6	1,231	14.8	2.00	14.8	NA	38%	21.5	0.4	140	32.5	6.04	1.766	0.508	X	X			No	
Forty Mile River	HH ROR		307	287	20	8000	30	6	11,719	67.4	2.00	134.8	NA	38%	214.9	5.0	440	30.5	11.09	2.834	0.832				X	No	
Mayo River	HH ROR		460	400	60	11000	40	6	16,600	62.3	1.00	62.3	250	38%	83.5	0.0	280	41.8	11.09	2.834	0.832					No	
Mush River	LH ROR		460	400	60	9000	40	6	3,720	30.6	1.00	30.6	172	50%	94.3	10.0	310	14.1	3.67	1.746	0.559					Yes	
North Fork Klotassie River	LH ROR		430	430	0	6000	3	3	1,542	16.2	1.00	16.2	193	50%	75.9	10.0	310	19.1	4.95	1.907	0.644			X		No	Will affect existing bridge and roads
Tisdin Creek	HH ROR		375	335	40	11000	9	12	6,981	77.7	1.10	85.4	NA	38%	284.2	4.1	220	48.2	13.91	3.000	1.038					No	
													Cluster 7: Proposed Mayo Transmission Extensions (1 of 9)													
Big Salmon Lake	Storage	LH ROR	703	703	0	10000	40	10	699	6.9	2.00	13.8	10	38%	23.3	0.1	80	41.7	11.49	4.742	1.634	X	X			No	
Fraser Falls	LH ROR		330	200	130	10000	40	12	10,831	376.1	0.40	150.5	10	38%	501.7	0.1	560	46.1	7.88	3.001	1.041					No	Would flood Hershenow Slough Habitat Protection Area
Seven Mile Canyon	LH ROR		987	907	80	250	37	10	11,609	116.1	0.00	92.9	23	70%	73.1	0.0	340	23.2	5.18	1.841	0.591					No	
													Cluster 8: Proposed Faro to Watson Lake 138 kV (1 of 3 Alternatives)													
Big Campbell Creek	HH ROR		980	860	120	10000	1	9	563	5.1	2.00	10.1	97	38%	32.3	2.0	160	16.5	4.70	1.473	0.556					No	
Blind Creek	HH ROR		782	671	111	8400	1	8	774	7.2	2.00	14.4	NA	38%	48.0	0.7	70	9.8	2.61	0.873	0.440					No	
Cabin Creek	LH ROR		707	692	15	300	7	12.6	12,220	154	0.83	128.8	15	60%	80.1	9.8	330	21.9	4.14	1.997	0.314					No	
Fallek Canyon (Frances River)	LH ROR		840	740	100	6000	3	11	1,542	16.2	1.50	24.3	NA	50%	94.9	15.4	210	12.9	2.21	1.034	0.170					No	
Finlayson Lake	Storage		840	740	100	6000	3	11	1,542	16.2	1.50	24.3	193	50%	94.9	15.4	210	10.6	2.21	1.034	0.170					No	
Finlayson with Lakes	Storage		840	740	100	6000	3	11	1,542	16.2	1.50	24.3	9	50%	94.9	15.4	210	10.6	2.21	1.034	0.170					No	
Frances River (Lower Canyon)	Unbonnet/Reservoir		685	685	0	250	13	12,800	1,664	15.4	0.95	64.2	102	70%	62.5	74.6	170	13.5	2.21	1.338	0.167					No	
Frances River (Middle)	Storage		695	695	0	250	13	12,800	1,664	15.4	0.95	64.2	102	70%	62.5	74.6	170	13.5	2.21	1.338	0.167					No	
Frances River (Upper Canyon)	Unbonnet/Reservoir		695	695	0	250	13	12,800	1,664	15.4	0.95	64.2	102	70%	62.5	74.6	170	13.5	2.21	1.338	0.167					No	
Frances River (Upper Canyon)	The Fingers around Upper Canyon Reservoir		745	745	0	20	3	12,800	1,664	15.4	0.95	64.2	102	70%	62.5	74.6	170	13.5	2.21	1.338	0.167					No	
Hoole Canyon	LH ROR		770	745	25	2 x 20	3	10	10,192	101.9	0.60	61.1	25.0	58%	61.5	5.9	210	17.6	3.48	1782	0.265					No	
Hoole Canyon with Fortin*	Storage		770	745	25	2 x 20	3	10	10,192	101.9	0.60	61.1	2 x 25	58%	73.7	43.4	260	21.1	4.14	2.234	0.281					No	Not revised for absence of Rose River to Watson TL
Hyland River	LH ROR		740	690	50	6,800	7	11.5	1,277	14.8	2.00	29.5	15	60%	78.9	9.8	330	22.3	4.14	1.997	0.314			X		No	Not revised for absence of Rose River to Watson TL
Lapie	LH ROR	Stewart Lake	840	740	100	6,000	3	11	1,542	16.2	1.50	24.3	193	50%	94.9	15.4	210	10.6	2.21	1.034	0.170					No	
Little Rancheria	HH ROR		840	740	100	11,000	8	11	1,539	17.7	2.00	35.4	157	50%	123.6	19.8	580	27.6	4.66	2.396	0.352				X	No	
Rose Canyon	HH ROR		705	665	40	11,000	8	11	1,539	17.7	2.00	35.4	NA	35%	48.0	0.9	340	21.9	7.15	1.889	0.538					No	
Rose Canyon	Short Tailrace to 705 Lake		705	665	40	11,000	8	11	1,539	17.7	2.00	35.4	NA	40%	55.2	1.7	90	14.9	4.26	1.377	0.324					No	
Quiney	HH ROR		711	703	8	4,800	4	9.8	582	4.7	2.00	9.3	NA	40%	20.2	1.7	90	14.9	4.26	1.377	0.324					No	
Ross Canyon	LH ROR		705	665	40	300	5	9	7,310	69.8	0.70	49.3	157	40%	79.6	6.8	240	16.2	3.16	1.621	0.240					No	
Ross Canyon	Short Tailrace to 705 Lake		705	665	40	4,300	11	9	1,397	12.3	2.00	24.6	78	40%	27.4	1.8	150	19.2	5.47	1602	0.413	X	X			No	
													Cluster 9: Proposed Beaver Creek to Haines Junction (6 of 6)													
Dyrland River	LH ROR		648	603	25	200	14	12,400	168.0	6.45	76.6	192	25	70%	70.0	6.7	330	22.3	4.69	2,264	0.3170					No	
White River	LH ROR		728	703	25	200	19	6,230	117.9	0.65	76.7	192	25	70%	70.0	6.7	240	19.7	3.40	1,600	0.2259					No	
Lynx and Wolverine	HH ROR		875	795	80	5,000	1	6.5	822	11.5	1.00	11.5	NA	40%	24.5	0.1	100	9.1	2.92	1,283	0.297					No	
Bonnet	HH ROR		875	795	80	5,000	21	6.5	822	11.5	1.00	11.5	NA	40%	24.5	0.1	100	9.1	2.92	1,283	0.297					No	
Duke	HH ROR		985	862	123	9,000	1	18	563	10.1	1.40	20.2	15	38%	21.5	0.4	100	13.9	3.70	1,302	0.291					No	
													Cluster 10: Whitehorse to Carcross to Skagway (1 of 5)													
Squanga Creek	HH ROR		769	690	79	8,600	4	11	843	3.6	2.00	7.2	NA	40%	13.3	1.3	100	27.2	7.77	1,985	0.564					No	
Wolf Creek	HH ROR		865	795	70	8,600	11	11	4,662	73.3	3.0	37.6	6.1	40%	131.3	2.1	240	22.3	2.78	2,171	0.314					No	
Wolf River with Wolf Lake*	**Storage**	**Bracket**	**865**	**795**	**70**	**12,600**	**11**	**11**	**4,662**	**73.3**	**3.0**	**37.6**	**233**	**40%**	**131.3**	**241.9**	**670**	**22.3**	**2.78**	**2,171**	**0.314**					**Yes**	
													Cluster 11: Carcross to Skagway (2 of 5)													
Mount Lorne	Storage		707	713.3	430	5,300	2	7.1	2,127	2.7	1.68	7.1	5	70%	19.9	2.8	177	24.9	8.85	1,941	0.564					No	
Tobin Wray Arm*	Storage		707	658	51	3,000	1	16	992	16.1	1.68	24.9	233	70%	71.1	59.2	280	19.6	2.64	1,497	0.223					Yes	Ecl. Location in Tobin Lake/Tooch/ Alpn Conservancy
													Cluster 12: Proposed Extension from Jake's Corner to Atlin (1 of 3)													
Atlin Hydro	Storage		672	724	107 and 56	4,600	100	8	350 and 630	4.4	1.60	7.0	7.9	23	54%	37 (of 46)	11 (of 21)	121	14.5	3.27	1,438	0.272					Yes	Reservoir Values

NOTES:
*Short Lake Ilex

0	10/21	ISSUED WITH REPORT	MS	RD	10/21
No.	DATE	REVISION DESCRIPTION	BY	CHK'D	APP'D

M:\1\01000\04\Report\~ Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Tables and Figures\Table 5.2 Hydro Summary Table.xlsx

6.0 SCREEN 3: FINAL SCREENING

6.1 ADDITIONAL SCREENING CRITERIA

The Screen 2 results were presented to YEC for review and guidance for the final screening and shortlisting of sites. During this phase, YEC requested the removal of the sites associated with two proposed transmission line segments:

- Cluster 8: Faro-Watson Lake
- Cluster 9: Beaver Creek-Hanes Junction

The removal of the sites associated with these transmission lines was based on low probability of these transmission line segments being developed in the foreseeable future.

Additional final screening criteria were implemented as follows:

- Sites below 10 MW except for Atlin;
- Sites consisting of dams on large river systems were removed due to perceived social risk and high temporary works construction costs
- Sites with a LCOE exceeding $0.35/kWh were removed

Table 6.1 presents the sites remaining for the final selection of the top five preferred sites.

Table 6.1 Sites for Final Selection

Project Name	Evaluated as	Cap.	Avg Energy	Winter Energy	Capital Cost	UCC	LCOE
		MW	GWh/a	GWh/a	M$	M$/MW	$/kWh
Primrose River	RoR	25	102	10	200	7.9	0.15
Primrose River	Storage	13	78	35	180	14.0	0.17
Wolf River	RoR	11	84	21	200	17.6	0.18
Tutshi Windy Arm	Storage	10	52	28	138	13.6	0.20
Wolf River with Wolf Lake	Storage	30	242	83	670	22.3	0.21
Atlin Hydro	Storage	8	37	17	121	15.5	0.22
Drury Creek	RoR	10	33	4	100	10.3	0.24
Reid Lakes & Lake Creek	Storage	11	42	16	140	13.5	0.26
Drury Creek	Storage	10	32	26	115	11.1	0.27
Lapie	RoR	13	45	3	170	13.3	0.29
Lake Creek	RoR	13	45	4	170	13.4	0.29
McQuestin	RoR	17	84	10	330	19.1	0.30
Anvil Creek	Storage	23	82	5	340	14.6	0.31

6.2 SELECTION OF TOP 5 SITES

The selection of the top five sites was made on a combination of comparative LCOE results for the sites presented in Table 6.1, and discussions with YEC for site-specific screening criteria. Four of the shortlisted sites were easily selected for their performance on an LCOE basis and their ability to provide winter energy:

- Primrose
- Drury
- Tutshi-Windy Arm
- Wolf

The fifth site for the shortlist was determined to be Atlin following a detailed conversation with YEC. While Atlin did not offer 10MW of capacity, the following additional considerations ultimately led to the decision:

- Lapie is a RoR project which would not offer any reliable winter generation capacity. Winter capacity is of primary importance to YEC, therefore this site was not selected.
- Reid Lakes and Lake Creek: involves two separate generating stations, with a RoR diversion project feeding a lake storage project. Each on its own is uneconomic, and the combined project is complex and requires an inter-basin transfer of water which is anticipated to pose a significant challenge for development.
- Atlin: while this site offers a lower installed capacity (8 MW), it is optimal for its winter generation potential. It is also considered lower risk than many other sites in terms of the available information supporting its design.

7.0 SHORTLIST CONCEPT DEVELOPMENT

7.1 PRIMROSE

The Primrose River and its tributaries form a hanging valley above Kusawa Lake, which make it a potentially very attractive site. Its presence within the boundaries of Kusawa Territorial Park means it was screened out of the 2016 KP study. The neighbouring drainage of Takhini Lake was also considered as part of proposed schemes in the past.

The Primrose site has been investigated on numerous occasions since 1952. The Demers 1989 Report forms the basis for the project configurations listed in the existing project inventories but were assumed to be using large dams. KP evaluated the project as both a RoR project and a storage project with a 10 m high dam and it is attractive in both instances.

A basic arrangement for the proposed project layout is shown on Figure 7.1. Key project parameters for this layout are as follows:

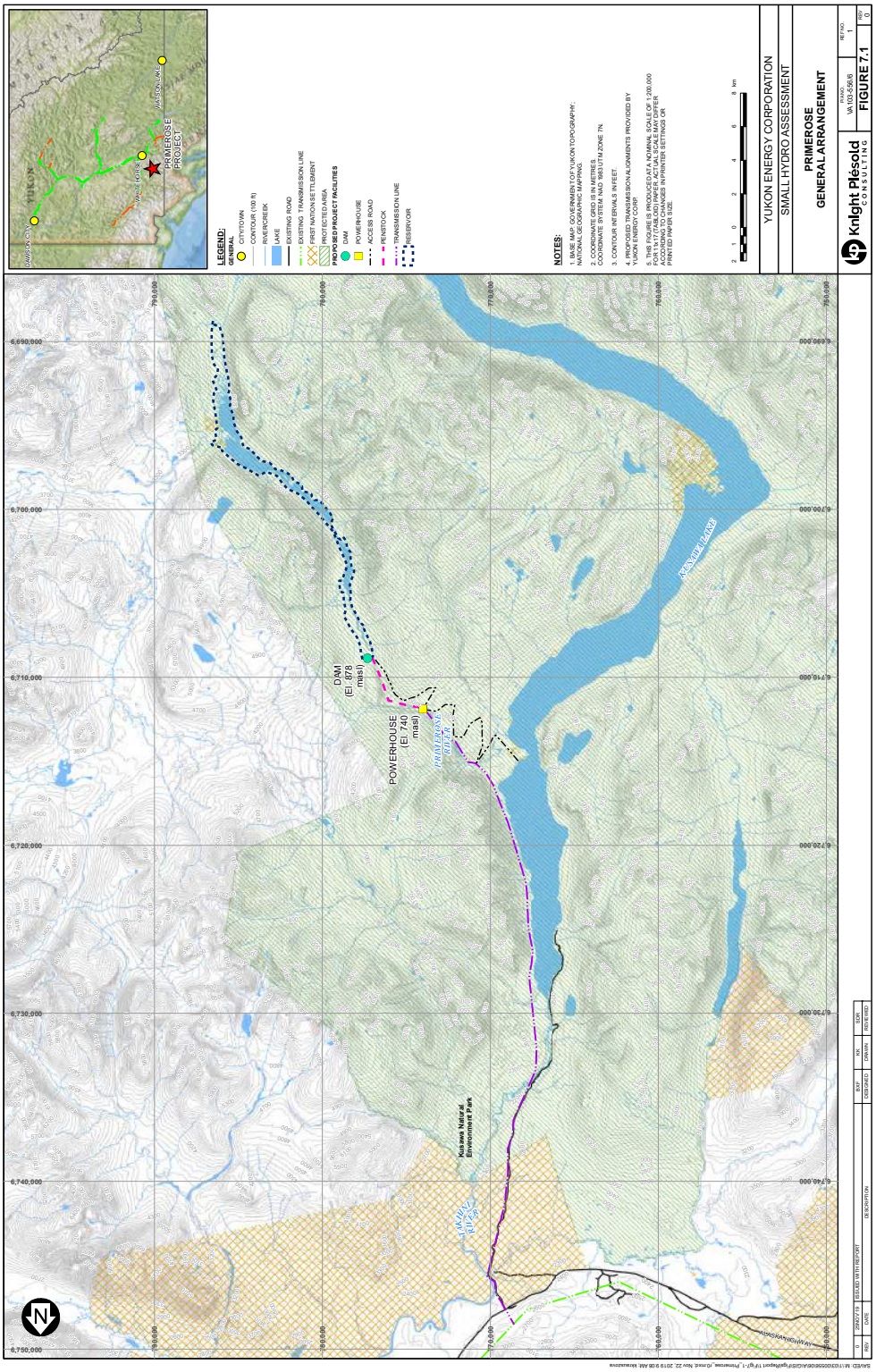
- Design Flow: 11.6 m^3/s.
- Gross Head: 138 m.
- Installed Capacity: 12.7 MW.
- Dependable Capacity: 12.7 MW (during the driest winter of synthetic record 1973-74 the project could generate for 97 continuous days during the winter at 12.7 MW).
- The current access assumes that the project site will require barge access and 20 km of new access roads to reach the proposed dam site from Kusawa Lake. 20 km of additional access road through the Kusawa Territorial Park would be required if the project site is not accessed/accessible by barge.
- A Rose Lake outlet control dam to provide 10 m of lake storage (operating storage of 100 million cubic metres (Mm^3)), equipped with IFR release system and spillway for flood water management.
- A 4,700 m long penstock.
- A Powerhouse (el. 740 masl).
- Substation and a 40 km long transmission line, with a t-tap interconnection to the existing 138 kV line between Aishihik and Whitehorse along Alaska Highway #1.

The project site is attractive but its presence in the Kusawa Territorial Park may be a major obstacle. Only one alternative to lower the powerhouse site to increase the project head at the expense of the increased penstock cost was considered. There could be a more optimal project layout once detailed topography for the site is obtained. Physical considerations at the proposed dam site are also unknown.

Table 7.1 presents the estimated average monthly energy output for the Primrose project. The project layout is shown on Figure 7.1.

Table 7.1 Primrose Average Monthly Energy (GWh)

	Primrose with Storage
Jan	9.0
Feb	8.1
Mar	7.0
Apr	0.0
May	0.0
Jun	0.1
Jul	6.7
Aug	9.0
Sep	8.7
Oct	9.0
Nov	7.6
Dec	9.0
Annual	74.0


PRIMEROSE PROJECT
Whitehorse
Watson Lake
Mayo
Dawson City
YUKON
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100 ft)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
TRANSMISSION LINE
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:200,000 FOR 11x17 PAPER SIZE. ACTUAL SCALE MAY VARY ACCORDING TO CHANGES IN PRINTER SETTINGS OR PRINT PAPER SIZE.
DAM
(El. 878 masl)
POWERHOUSE
(El. 740 masl)
PRIMROSE RIVER
McGUIRE LAKE
Kaska Natural Environment Area
LIARD RIVER
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
PRIMEROSE
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
FIGURE 7.1

7.2 DRURY

The Drury Lake Project is located on Drury Creek between Drury Lake and Little Salmon Lake, in the Yukon River watershed. The site is approximately 170 km north of Whitehorse and is situated within 1 km of the Robert Campbell Highway and the existing transmission line.

The Drury site was evaluated as both a run of river project and a storage project. The available stream gauge information for Drury seems to indicate some natural flow attenuation from Drury lake offering some winter generation even on a RoR basis.

This project was short listed as it has a relatively low LCOE and offers the opportunity to generate winter energy. It was carried forward as a storage project but may also be valuable as a RoR project.

A variety of studies have previously been commissioned for the Drury site, including high level reconnaissance, geotechnical investigations, and design studies, and these have resulted in several alternative design concepts. The most recent study, apart from the 2016 KP study, was completed by KGS in 2008 and provides basic site layouts, design and geotechnical considerations, and cost estimates for different options.

While earlier studies considered a low gradient canal and a short penstock, geotechnical risk and the presence of permafrost were noted by KGS. At this desktop level, the conveyance alignment and specific constructability concerns cannot be addressed in any detail beyond that reported by KGS, and so the selection of a buried low-pressure penstock instead of a canal has been adopted by KP.

A preliminary general arrangement of the project layout is shown on Figure 7.2. Key project parameters and characteristics for this layout are as follows:

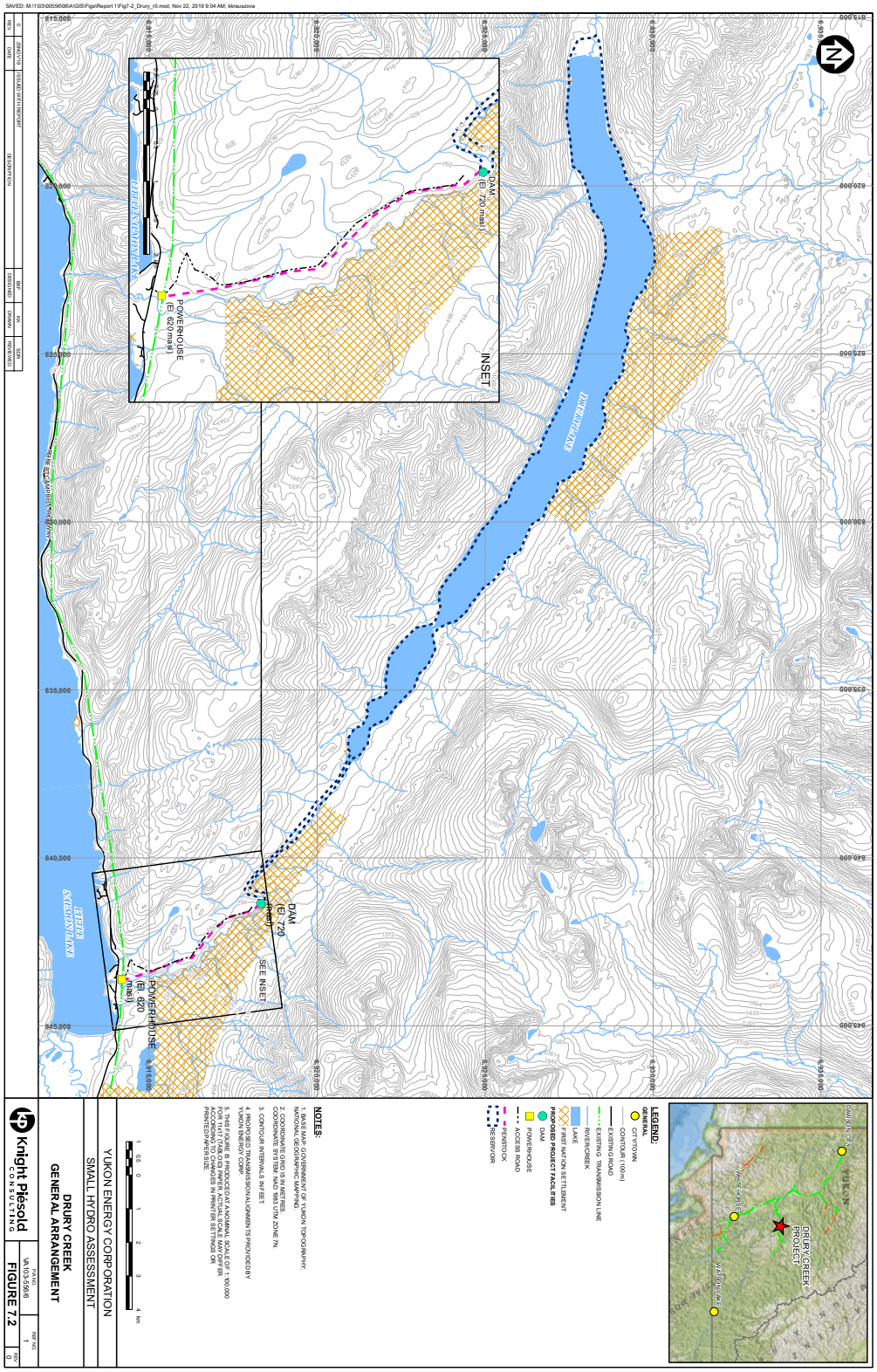
- Design Flow: 12.7 m^3/s.
- Gross Head: 100 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1998-99 the project could generate for 63 continuous days during the winter at 10 MW).
- 5.3 km of access roads from the Robert Campbell Highway to the powerhouse, along the water conveyance, and upstream to the outlet of Drury Lake.
- Concrete Faced Rockfill Dam (CFRD) at the outlet of Drury Lake to provide 5 m of storage (operating storage of 130 Mm^3). The dam would be constructed with an IFR discharge system and a spillway to Drury Creek for flood water management.
- An intake structure.
- 4.9 km penstock located on the south side of Drury Creek (alignment as previously indicated by KGS).
- Powerhouse (El. 620 masl) and substation at the edge of Drury Creek, upstream of the Robert Campbell Highway and the river mouth at Little Salmon Lake.
- 0.5 km transmission line, with t-tap interconnection to the existing transmission line.

Note: The lack of detailed topography makes siting the location and configuration of the projects point of diversion difficult. The existing topography shows 5 km of very flat terrain and stream gradient at the outlet of Drury Lake, as such the current option assumes a single structure would be enough to provide impoundment and a penstock offtake.

Table 7.2 presents the average estimated energy output for the Drury project.

Table 7.2 Drury Average Monthly Energy (GWh)

	Drury
Jan	7.2
Feb	6.1
Mar	4.4
Apr	0.0
May	0.0
Jun	0.0
Jul	0.0
Aug	0.2
Sep	1.7
Oct	2.2
Nov	1.6
Dec	7.2
Annual	30.6


SAVED: M:\1\03\00558\08A\GIS\Fig\Report 1\Fig7-2_Drury_r0.mxd; Nov 22, 2019 9:04 AM; tkrauszova
INSET
DAM (El. 720 masl)
POWERHOUSE (El. 620 masl)
SEE INSET
DAM (El. 720 masl)
POWERHOUSE (El. 620 masl)
LAKE LABERGE
LITTLE SALMON LAKE
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (100m)
EXISTING ROAD
EXISTING TRANSMISSION LINE
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
POWERHOUSE
ACCESS ROAD
PENSTOCK
RESERVOIR
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY, NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:100,000 FOR PAPER SIZE ANSI B (11" x 17"). ACTUAL SCALE MAY DIFFER IF PRINTED ON OTHER PAPER SIZES OR IF PRINTER SETTINGS ARE CHANGED FROM DEFAULT PRINTER/PAPER SIZE.
DRURY CREEK PROJECT
WHITEHORSE
WATSON LAKE
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
DRURY CREEK
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
FIGURE 7.2
VA101-558/8
REF NO. 1
REV 0
DESIGNED
DRAWN
REVIEWED
DESCRIPTION
DRAFT
ISSUED WITH REPORT
DATE
REV

7.3 TUTSHI WINDY ARM

The Tutshi – Windy Arm Project is a proposed storage hydropower development located between Tutshi Lake and Windy Arm of Tagish Lake in northern British Columbia. Tutshi and Tagish Lakes are tributaries to the Yukon River. The project site is approximately 45 km to the south of Carcross, Yukon, and the proposed powerhouse location is within 1 km to the east of the Klondike Highway.

Several studies have previously been completed for this site, including geotechnical investigations, design, and cost estimates, resulting in a number of alternative design concepts. This desktop study is based on the most current concepts, presented in the 2008 KGS report.

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water.

A basic arrangement for the proposed project layout is shown on 3. Key project parameters for this layout are as follows:

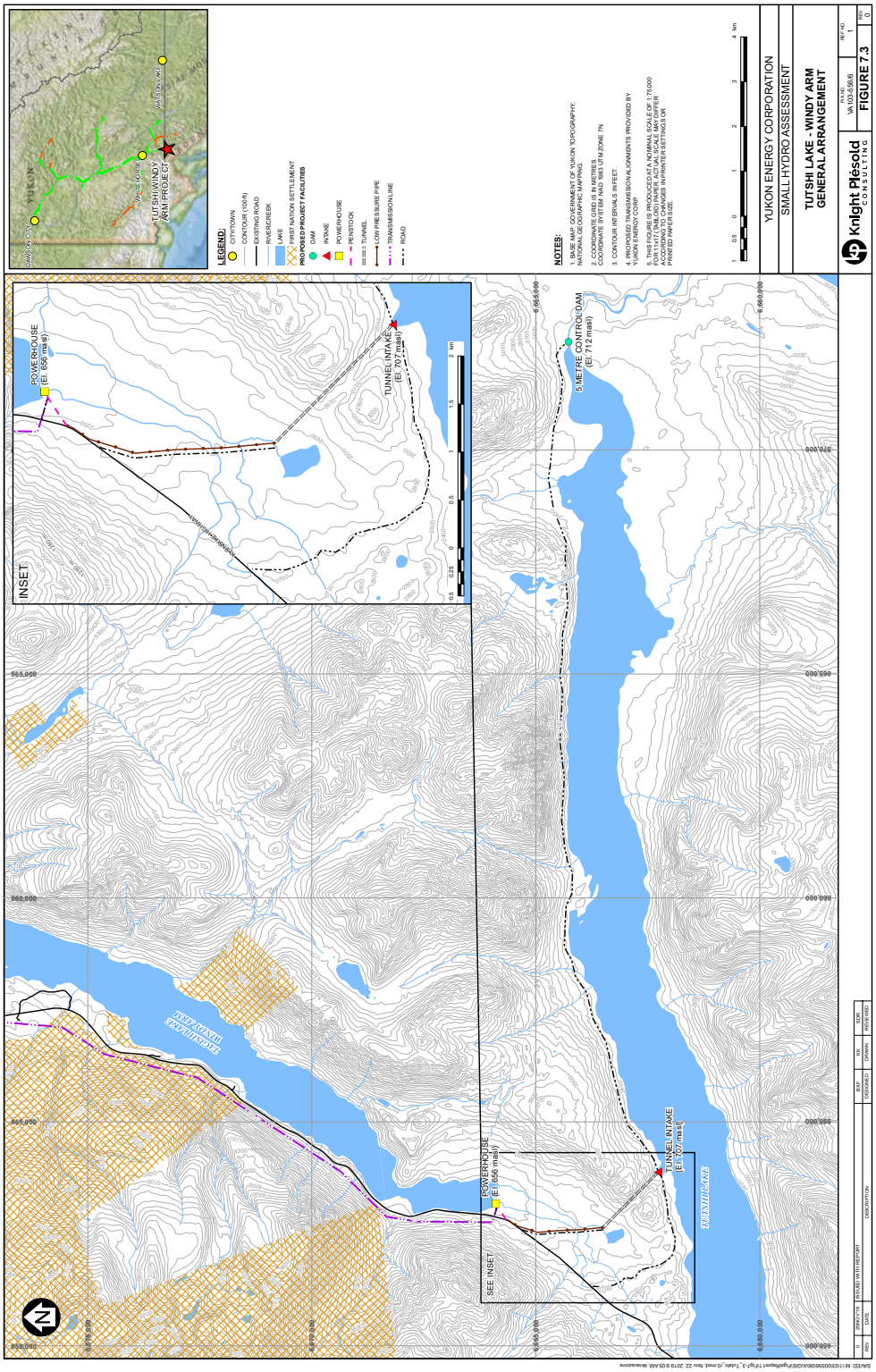
- Design Flow: 25 m3/s.
- Gross Head: 51 m.
- Installed Capacity: 10 MW.
- Dependable Capacity: 10 MW (during the driest winter of synthetic record 1973-74 the project could generate for 108 continuous days during the winter at 10 MW).
- 23.5 km of access roads, to reach the powerhouse, surface conveyance, tunnel intake, and outlet control dam on Tutshi Lake.
- Tutshi Lake outlet control dam to provide 5 m of lake storage (operating storage of 267 Mm3), equipped with IFR release system and spillway for flood water management.
- Tunnel intake and 1.7 km tunnel through the hill separating the north end of Tutshi Lake from Windy Arm of Tagish Lake (Intake El. 707 masl).
- 2.7 km long penstock.
- Powerhouse on the south shore of Windy Arm, Tagish Lake (El. 656 masl).
- Substation and a 1 km long transmission line, with t-tap interconnection to a proposed transmission line along the Klondike Highway between Carcross and Skagway (AK).

The Taku River Tlingit First Nation and Carcross Tagish First Nation would need to be approached prior to any serious consideration of the project site. Site investigations and a more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Table 7.3 presents the average monthly energy output for the Tutshi-Windy Arm project. The project arrangement is shown on Figure 7.3.

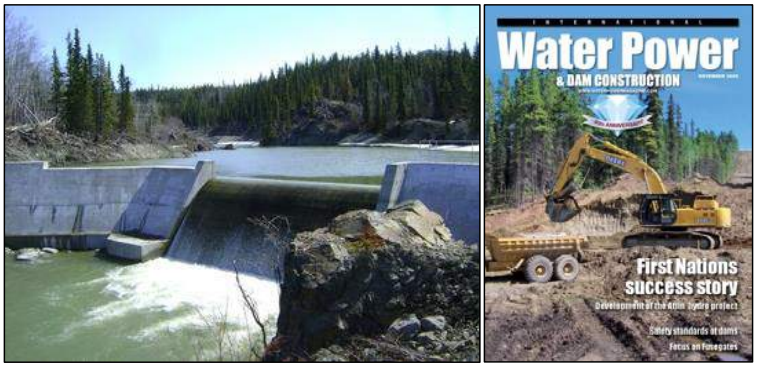
Table 7.3 Tutshi Average Monthly Energy (GWh)

	Tutshi
Jan	7.1
Feb	6.5
Mar	6.2
Apr	0.0
May	0.0
Jun	0.0
Jul	0.4
Aug	5.4
Sep	6.7
Oct	6.4
Nov	3.4
Dec	7.1
Annual	49.3


LEGEND:
CITY/TOWN
CONTOUR (100 ft)
EXISTING ROAD
RIVER/CREEK
LAKE
FIRST NATION SETTLEMENT
PROPOSED PROJECT FACILITIES
DAM
INTAKE
POWERHOUSE
PENSTOCK
TUNNEL
LOW PRESSURE PIPE
TRANSMISSION LINE
ROAD
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
2. COORDINATE GRID IS IN METRES.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN FEET.
4. PROVISED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORPORATION.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:75000 FOR 11x17 (TABLOID) PAPER. ACTUAL SCALE MAY DIFFER IF PAPER SIZE CHANGES IN PRINTER SETTINGS OR PRINTED PAPER SIZE.
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
TUTSHI LAKE - WINDY ARM
GENERAL ARRANGEMENT
Knight Piésold CONSULTING
FIGURE 7.3
INSET
POWERHOUSE (El. 656 masl)
TUNNEL INTAKE (El. 712 masl)
5 METRE CONTROL DAM (El. 712 masl)
SEE INSET
TUTSHI LAKE
WINDY ARM

7.4 ATLIN HYDRO

Atlin is an isolated community located approximately 50 km south of the Yukon-British Columbia border. Atlin is only road accessible from the Yukon Territory. On April 1, 2009 the 2.1 MW Atlin Hydro Project began commercial power production (Illustrated in Figure 7.4). The hydropower facility is owned by Xeitl Limited Partnership which is 100% owned by Taku River Tlingit First Nation. The project is located on Pine Creek and is approximately 4 km east of the community of Atlin, BC. The facility overlaps with previously conceived layouts of a Surprise Lake hydroelectric project.



NOTES:
1. PHOTO SOURCE: WWW.WATERPOWERMAGAZINE.COM.

Figure 7.4 Atlin Hydro Project Photos

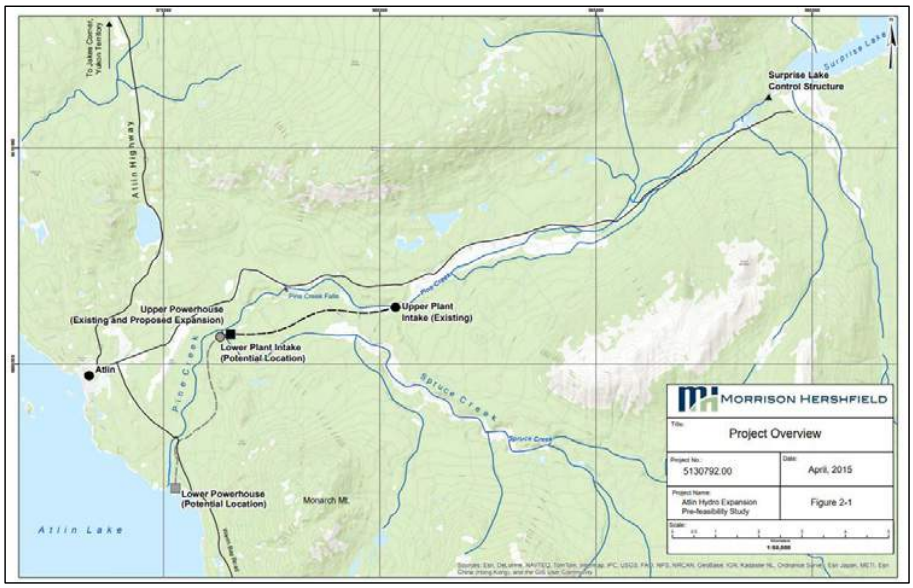
On June 23, 2016 Morrison Hershfield provided YEC with a detailed report on the Atlin Hydro Expansion Project. The report includes a transmission line options assessment for connection to the Yukon electrical system. The detail provided in this report (good quality topography, complete hydrological assessment, detailed drawings and estimates) means this project has less unknowns and risks than the other projects in this short list.

For the purpose of conciseness, the Morrison Hershfield information will only be repeated here in brief summary. They have completed an alternatives assessment, a hydrological assessment and a Pre-Feasibility Assessment. The proposed general arrangement is shown in Figure 7.5. A summary of the estimated energy is shown in Table 7.4 The conclusion is quoted below.

“It is proposed to develop a total of 7.8 MW at Pine Creek, consisting of expanding the existing (upper) 2.1 MW powerhouse with an additional two turbines to bring the total installed capacity to 5 MW plus the addition of a second, or lower, powerhouse near Atlin Lake with an installed capacity of 2.8 MW. The upper power plant operates under a gross head of approximately 107 m and the lower plant has a gross head of approximately 56 m.”

“For the expansion of the upper power plant, a second 4 km long HDPE penstock will be required to convey a maximum flow of 3.55 m³/s from the existing head pond to the powerhouse. The penstock will require the excavation of a trench, mainly through overburden materials except some limited bedrock excavations near the intake structure. The lower power plant requires 4 km of twin HDPE penstocks to convey a maximum

flow of 7 m³/s. A new excavated head pond just downstream of the existing (upper) powerhouse is required to supply the lower penstocks. Spruce Creek would be diverted into the lower head pond such that flows from Spruce Creek can be used to increase electrical generation at the lower power plant.



NOTES:
1. SOURCE: ATLIN HYDRO EXPANSION STUDY.

Figure 7.5 Atlin Hydro Project and Surprise Lake

Increased storage in Surprise Lake to maximize winter electrical generation will be developed by modifying the existing control structure at the lake outlet. It is proposed to increase the storage range from 1.1 m to 2.5 m by increasing both top and bottom storage by approximately 0.7 m. This operating scheme would not require modification of the project's existing Permit Over Crown Land which allows storage of water up to elevation 913.85 masl. The storage of water allows the project to generate approximately 70% of its annual average energy production during winter months (November through April). Winter energy is of highest value to the Yukon's electrical grid.

In consideration of the existing hydropower infrastructure the Atlin Hydro Expansion Project has the potential to produce on average 44.7 GWh/yr of energy, of which at 36 GWh/yr is available for export to the Yukon after the community of Atlin's needs are met. Cost for the hydroelectric development only (without transmission) are estimated at $79.7 million. A total project cost of $120.7 million is estimated, including a 69 kV transmission line to connect with the Yukon's electrical grid at Jakes Corner."

Table 7.4 Atlin Average Monthly Energy (GWh)

	Production	Committed	For Yukon
Jan	5.1	1.0	4.1
Feb	4.9	0.8	4.1
Mar	5.3	0.8	4.5
Apr	4.5	0.8	3.7
May	2.4	0.7	1.7
Jun	3.3	0.6	2.7
Jul	2.2	0.5	1.7
Aug	1.7	0.5	1.2
Sep	2	0.6	1.4
Oct	2.3	0.7	1.6
Nov	5.5	0.7	4.8
Dec	5.5	0.9	4.6
Annual	44.7	8.6	**36.1**

7.5 WOLF RIVER

The Wolf River is a tributary of the Nisutlin River upstream of Teslin Lake, in the headwaters of the Yukon River. The Wolf River Project site is located near the river mouth and approximately 22 km to the northeast of the community of Teslin and the Alaska Highway. First Nation Heritage Routes and First Nation Settlement Lands associated with the Teslin Tlingit Council are visible in the GeoYukon database covering the area adjacent to the north bank of the Wolf River.

The previous KP report and the 1990 and 1991 Hydro Investigations by S. Demers looked at the project site. Little is known of site-specific geotechnical conditions and cannot be confirmed at the desktop level. There are several project configurations possible and the main limitation on the project installed capacity is associated with the capacity of the existing 34 kV transmission line from Teslin. In the current layout the main intake has been placed below the confluence of Caribou Creek and Wolf River (previously the intake was considered a bit higher in the basin missing out on the Caribou Creek catchment.) The 1991 study also noted the potential opportunity for storage in Wolf Lake, which could improve winter generation and the plant capacity factor.

Two project configurations were considered in the first a run-of-river project limited by the existing transmission and capped at 11 MW of installed capacity. A second utilizing the potential of the site at 30 MW with the addition of storage at Wolf Lake to allow for firm winter generation but requiring an additional higher capacity of transmission line to Whitehorse.

A basic general arrangement for the proposed project layout is shown on Figure 7.6.

Key project parameters for this layout are shown below.

Table 7.5 Wolf River Alternatives

Sites	Wolf River	Wolf River and Wolf Lake
Design Flow	18.8	37.6
Gross Head (m)	75	100
Installed Capacity (MW)	11.2	30.0
Dependable Capacity (MW)	4.0	30.0
Canal Length (m)	6,900	11,500
Penstock Length (m)	1,300	900
Transmission Line (km)	20	20+150

Project access should be able to circumvent the Nisutlin River Delta National Wildlife Area. Access to the project site can be done through either or both of the following:

- Upgrades to an existing 34 km trail identified as leaving the Alaska Highway (#1) 20 km east of Teslin.
- A new 23 km access road departing from Teslin, running west of the Nisutlin River Delta National Wildlife Area. This option would require a bridge across the Nisutlin River.
- 73 km of trail upgrades are required to access Wolf Lake from the proposed intake site.

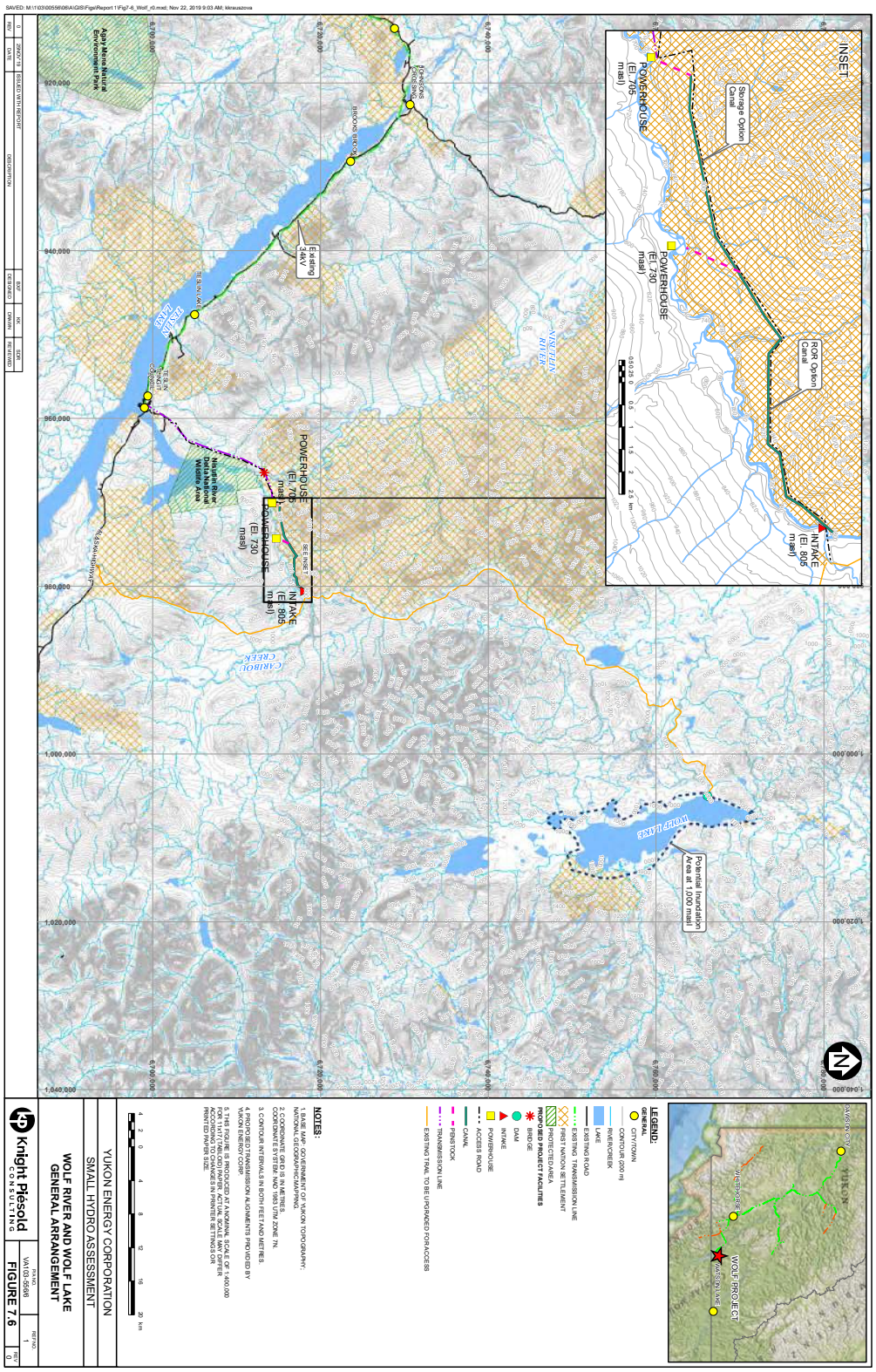
Both project configurations would require a canal diversion and a forebay to the penstock and a powerhouse and a short tailrace channel back to Wolf River.

Both configurations would include a substation and 23 km transmission line to Teslin. Development of a large generating capacity at Wolf River would need a more careful consideration of the transmission line capabilities and energy demand. For the current assessment valuation, it was presumed that 150 km of new line would be needed to connect Teslin to Whitehorse through Jake's Corner to support a 30 MW project site.

Table 7.6 presents the average monthly energy output for the Wolf River project. The project arrangement is shown on Figure 7.6.

Table 7.6 Wolf and Wolf Lake Average Monthly Energy (GWh)

	Wolf	Wolf River and Wolf Lake
Jan	5.7	21.2
Feb	3.9	19.0
Mar	3.9	17.2
Apr	4.8	12.8
May	7.8	19.3
Jun	7.7	20.6
Jul	8.0	21.2
Aug	8.0	21.0
Sep	7.7	20.1
Oct	8.0	20.2
Nov	7.5	15.6
Dec	6.9	21.2
Annual	79.7	229.5


INSET
POWERHOUSE (El. 705 masl)
POWERHOUSE (El. 730 masl)
INTAKE (El. 805 masl)
Storage Option Canal
ROR Option Canal
Existing 34kV
Potential Inundation Area at 1,000 masl
WOLF LAKE
HEALY LAKE
CARBON CREEK
BROOKING BROOK
Agay Mene Natural Environment Park
Nisutlin River Delta National Wildlife Area
LEGEND:
GENERAL
CITY/TOWN
CONTOUR (200 m)
RIVER/CREEK
LAKE
EXISTING ROAD
EXISTING TRANSMISSION LINE
FIRST NATION SETTLEMENT
PROTECTED AREA
PROPOSED PROJECT FACILITIES
BRIDGE
DAM
INTAKE
POWERHOUSE
ACCESS ROAD
CANAL
PENSTOCK
TRANSMISSION LINE
EXISTING TRAIL TO BE UPGRADED FOR ACCESS
NOTES:
1. BASE MAP: GOVERNMENT OF YUKON TOPOGRAPHY; NATIONAL GEOGRAPHIC MAPPING.
COORDINATE SYSTEM: NAD 1983 UTM ZONE 7N.
3. CONTOUR INTERVALS IN BOTH FEET AND METRES.
4. PROPOSED TRANSMISSION ALIGNMENTS PROVIDED BY YUKON ENERGY CORP.
5. THIS FIGURE IS PRODUCED AT A NOMINAL SCALE OF 1:400,000 FOR 11x17 (B) LANDSCAPE PAPER. FIGURE SCALE MAY DIFFER ACCORDINGLY WHEN PRINTED ON OTHER PRINTER PAPER SIZES.
Knight Piésold CONSULTING
YUKON ENERGY CORPORATION
SMALL HYDRO ASSESSMENT
WOLF RIVER AND WOLF LAKE GENERAL ARRANGEMENT
FIGURE 7.6
PA10-00/08
REF.NO
1
REV.
0

8.0 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

The objectives of the study were to compile a regional assessment of hydropower development sites with installed capacities between 10 MW and 30 MW and within 50 km of existing or proposed transmission lines. KP developed a list of 147 sites and completed a hydropower screening assessment to progressively eliminate the less attractive sites and focus in on the best potential hydroelectric development options. Following a coarse screening of these 147 sites, 56 Sites were selected for a further quantitative assessment. KP performed a quantitative assessment to determine potential layouts, capacity, average annual and winter energy yield and indicative development costs. During a final screening and selection process, the sites were presented to YEC for final consideration and implementation of additional screening criteria. The final screening was based on capacity, location, expected development costs and perceived social acceptability. This narrowed the 56 sites to nine sites, including:

- Primrose (as both ROR and lake storage projects)
- Wolf River (with and without Wolf Lake)
- Tutshi Windy Arm
- Atlin
- Drury Creek (as both ROR and lake storage projects)
- Lake Creek and Reid Lakes
- Lapie
- McQuestin River
- Anvil Creek

These 9 sites were assessed in more detail, and the final 5 preferred sites were selected as:

- Primrose (as a lake storage project)
- Drury (as a lake storage project)
- Tutshi Windy Arm
- Atlin
- Wolf River (with and without Wolf Lake)

A summary of the Financial and Technical attributes of the preferred sites is presented in Table 8.1.

Knight Piésold CONSULTING

TABLE 8.1

YUKON ENERGY CORPORATION
HYDROPOWER POTENTIAL ASSESSMENT (10MW-30MW)

PREFERRED SITES
SUMMARY

Print Nov/25/19 09:00:03

DESCRIPTION	Primrose	Drury	Tutshi	Atlin	Wolf	Wolf River & Lake
Installed Capacity (MW)	12.7	10.0	10.0	8.0	11.2	30.0
Dependable Winter Capacity (MW) based on 2 weeks of Winter Production	12.7	10.0	10.0	6.0	4.0	30.0
Average Annual Energy (GWh) x 95% for outages and transmission losses	74.0	30.6	49.3	45.0	79.7	229.5
Average Dec-Mar Energy (GWh) x 95% for outages and transmission losses	33.0	24.9	27.1	20.8	20.1	79.0
Unit Cost of Capacity (M$/MW)	14.0	11.1	16.7	16.4	14.7	15.3
Unit Cost of Energy (M$/GWh)	2.40	3.61	3.39	2.91	2.07	2.00
Levelized Cost of Capacity ($/kW-yr) @4.82%	1,342	673	1,291	1,426	1,780	1,764
Levelized Cost of Energy ($/kWh) @4.82%	0.184	0.277	0.256	0.222	0.160	0.154
Levelized Cost of Winter Energy ($/MWh) @4.82% and 0.19 $/kWh for Non Winter Energy	0.177	0.296	0.311	0.259	0.072	0.086
Project Gross Head (m)	138	100	51	107 and 56	75	100
Design Flow (m^3/s)	11.6	12.7	24.9	7.0	18.8	37.6
MAD (m^3/s)	14.5	4.9	16.2	4.4	75.3	75.3
Design Factor	0.80	2.60	1.55	1.59	0.25	0.50
Dam Height (m)	10	5	5	2.5	-	4
Storable Volume (10^6 m^3)	100	125	265	76	-	350
Water Conveyance Length (m)	4,700	5,200	3,000	4,000	7,400	14,000
Capital Cost Esitmate						
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$ 29,700,000	$ 18,500,000	$ 27,900,000	$ 1,400,000	$ 27,600,000	$ 57,900,000
Access and Site Preparation	$ 8,000,000	$ 4,600,000	$ 7,900,000	$ 700,000	$ 12,000,000	$ 23,000,000
Intake, Forebay, and Headrace	$ 6,500,000	$ 6,800,000	$ 12,500,000	$ 1,100,000	$ 10,000,000	$ 25,000,000
Water Conveyance System	$ 25,000,000	$ 30,000,000	$ 32,900,000	$ 30,200,000	$ 39,700,000	$ 90,000,000
Powerhouse and Ancilary Services	$ 6,000,000	$ 5,900,000	$ 8,700,000	$ 12,700,000	$ 7,400,000	$ 13,500,000
Power Generation Equipment (Water to Wire)	$ 8,900,000	$ 7,100,000	$ 7,100,000	$ 9,800,000	$ 7,900,000	$ 20,000,000
Switchyward, Transmission and Interconnection	$ 29,500,000	$ 2,700,000	$ 20,200,000	$ 27,100,000	$ 15,000,000	$ 18,000,000
Dams and Reservoirs	$ 15,000,000	$ 4,500,000	$ 3,800,000	$ 1,600,000	$ -	$ 3,500,000
Upgrades to Grid (138 kV 150 km Teslin to Whitehorse)					$ -	$ 82,500,000
SUB-TOTAL	**$ 128,600,000**	**$ 80,100,000**	**$ 121,000,000**	**$ 84,600,000**	**$ 119,600,000**	**$ 333,400,000**
EPCM ENGINEERING COST (8 % of ESTIMATED CONSTRUCTION COST)	$ 10,300,000	$ 6,400,000	$ 9,700,000	$ 20,300,000	$ 9,600,000	$ 26,700,000
CONTINGENCY (30 % of ESTIMATED CONSTRUCTION COST)	$ 38,600,000	$ 24,000,000	$ 36,300,000	$ 26,100,000	$ 35,900,000	$ 100,000,000
TOTAL ESTIMATED CAPITAL COST	**$ 177,500,000**	**$ 110,500,000**	**$ 167,000,000**	**$ 131,000,000**	**$ 165,100,000**	**$ 460,100,000**

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NOTES:
1. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
2. DOES NOT INCLUDE APPLICABLE SALES TAXES.
3. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
4. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.
5. ATLIN COSTS ARE BASED COSTS REPORTED BY MORRISON HERSFIELD 2016 ESCALATED AT 2.5%.

REV	DATE	DESCRIPTION	PREP'D	CHK'D
0	25NOV19	ISSUED WITH REPORT VA103-556/6-1	BXF	SDR

8.2 RECOMMENDATIONS

8.2.1 FIRST NATIONS

All 5 of the sites (Primrose, Drury, Tutshi, Atlin, and Wolf River) short listed for concept development will require the involvement of First Nations and other stakeholders to make them a success. In British Columbia, renewable energy has become an important industry for First Nations and it has been an industry First Nations have embraced because projects can be developed with minimal impacts to their rights, environment, and within their values. It is possible the Yukon may experience a similar situation.

Judith Sayers for the BC First Nations Clean Energy Working Group indicates that First Nations with clear Economic Development Plans, Land Use Plans and Community Energy Policies in place before they start involvement with renewable energy projects have an easier time finding an acceptable community direction regarding such projects. Ensuring that renewable energy development is considered in those plans is of key importance. (Source: https://www.cleanenergybc.org/wp-content/uploads/2016/04/BC-FN-Toolkit.pdf).

8.2.2 TECHNICAL EVALUATION

Further evaluation of the preferred sites is recommended, to improve the design basis, project configurations, and understanding of hydrological and geotechnical conditions. The following activities are recommended:

- Set the projects energy objectives, including the required installed capacity and winter energy generation potential to meet the forecasted energy and power demands in the Yukon
- Undertake a screening assessment of social and environmental permitting constraints at each of the five preferred sites
- Obtain accurate mapping (such as satellite topography) for the proposed project areas to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines
- Implement hydrological data collection programs at the preferred sites or reinforce existing programs
- Conduct preliminary site visits to the preferred sites to further evaluate technical viability
- Update energy estimates based on hydrology data and accurate depth-area-capacity curves for reservoirs
- Update quantity and cost estimates

Should the above assessment indicate that there are no critical technical or environmental barriers to development, detailed evaluation of the sites through pre-feasibility and feasibility studies should be pursued to prove economic viability.

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10.0 CERTIFICATION

This report was prepared and reviewed by the undersigned.

Prepared:

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Approval that this document adheres to the Knight Piésold Quality System:

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

APPENDIX A

Historical Documents and Hydropower Project Sites

(Table A.1)

Knight Piésold CONSULTING

VA103-556/6-1 Rev 0
November 25, 2019

Knight Piésold CONSULTING

TABLE A.1

YUKON ENERGY
REGIONAL HYDROPOWER ASSESSMENT

HISTORICAL DOCUMENTS AND HYDROPOWER SITES

Print Nov/25/11

Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Date	Aug-66	Jan-08	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-80	Aug-81	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1986	Dec 1990	Jan-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15	
Author	Department of Mines and Technical Surveys	T. Ingledow & Associates Ltd.	Montreal Engineering	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Morenco Consultants Pacific	Shawinigan Engineering	Morenco Consultants Pacific	Shawinigan Stanley	Northwest Hydraulic Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Consultants Ltd.	Crippen Consultants	Crippen Consultants	Morenco Consultants Pacific	Morenco Consultants Pacific	Morenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author. Stored in	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc.
Title	A Preliminary Appraisal of the Water Power Resources of the Hydro-electric Resources Survey of the Central Yukon Territory	Northern Canada Power Commission - Francis River	Power Survey of the Liard River	Electrification of Mayo with the Yukon (Main Report, Technical	The Development of Power in the Francis River - Upper Canyon: Preliminary Study of a 25.2 MW	Mid-Yukon Feasibility Study: Year 1, Vol 1: Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibility Study: Mid-Study Report	Environmental and Socio-Economic Studies of Five Hydro	False Canyon Hydro Prefeasibility Study	Granite Canyon Development Pre-feasibility Study	Prefeasibility Study of a Hydroelectric Site Near	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Prefeasibility Study	Yukon Hydro Investigations Consolidated Report from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites: A Review of	Yukon Energy Corporation: 1989 Hydro Investigations	Yukon Energy Corporation: 1990 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites - Concept	2008 Lake Laberge Water Level Evaluation Draft Report	Preliminary Power Potential Assessment for Homan Lake	EMAL: Next Generation Hydro Project	Yukon Next Generation Hydro and Transmission Visibility Study	Yukon Next Generation Hydro and Transmission Visibility Study
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Project Name																												
Aberdeen Canyon					x														x					x			x	
Alder Creek																												
Anvil Creek		x			x														x	x						x	x	
Atlin Storage																							x	x		x	x	
Bates Canyon					x																						x	
Bates Canyon + Dezadeash Diversion					x														x								x	
Beaver Crow				x															x					x			x	
Bell					x														x					x			x	
Big Campbell Creek																												
Big Kalzas Lake		x			x														x								x	
Big Salmon					x														x					x			x	
Blind Creek																												
Bonanza Creek																												
Bonnet Plume																								x			x	
Boundary					x														x								x	
Bradens Canyon		x			x														x					x			x	
Bradens Canyon + Fortin Lake Dam		x			x														x					x			x	
Britannia					x														x					x			x	
Burwash																												
Campbell Creek																								x			x	
Cassiar Bar																								x			x	
Chandindu River		x			x																	x					x	
Coal River																											x	
Dawson					x														x					x			x	
Detour Canyon		x			x																			x			x	x
Detour Canyon + Fortin Lake Dam		x			x														x					x			x	x
Doll Creek																												
Donjek to White River Diversion		x																	x			x					x	
Drury Creek		x			x															x	x		x			x	x	
Duke																												
Eagle's Nest Bluff (Alone)							x				x								x					x			x	
Eagle's Nest Bluff + Rink Rapids (1 PH)							x				x								x					x			x	
Eagle's Nest Bluff + Rink Rapids (2 PH)							x				x								x					x			x	
Earn		x			x														x	x							x	
Ethel Lake		x			x														x								x	
False Canyon				x	x				x	x	x	x					x							x			x	x
Fantasque				x															x					x			x	
Fifteen Mile Diversion		x			x														x			x					x	
Finlayson																					x			x		x	x	
Five Fingers High (150 MW)					x														x					x			x	
Five Fingers High (455 MW)					x														x					x			x	
Five Fingers Low (75 MW)					x														x					x			x	
Forty Mile River		x			x														x			x					x	
Frances River (Lower Canyon)				x	x																			x			x	x
Fraser Falls (High)		x			x														x					x			x	x
Fraser Falls (Low)		x			x																			x			x	x
Gladstone Diversion																							x				x	
Glenlyon																												
Granite Canyon (Large)		x			x						x		x						x		x			x			x	x
Granite Canyon (Small)		x			x						x		x						x		x			x			x	x
Hess Canyon		x			x														x								x	
Homan Lake																						x		x	x		x	
Hoole Canyon		x									x									x				x			x	
Hoole Canyon + Fortin Lake Dam		x			x				x		x				x	x	x			x				x			x	x
Hoole River																								x			x	
Hootalinqua					x														x								x	
Hyland Diversion				x															x		x			x			x	
Ibex																												
Independence		x			x														x					x			x	
Indian River		x			x														x			x					x	
Kathleen Canyon																								x			x	
Kluane Canyon		x			x														x	x						x	x	
Koidern																												
Lake Creek Diversion		x			x														x								x	
Lapie																						x				x	x	
Liard Canyon				x	x														x		x			x			x	
Little Rancheria River																								x			x	
Little Salmon Dam									x										x								x	
Little Salmon Diversion		x			x															x							x	
Lower Canyon on White River		x			x														x								x	
Lynx and Wolverine																												
McNaughton Creek																					x		x				x	
McNeil		x			x														x								x	
McQuestin																												
Meister River																								x			x	
Mica Creek		x			x														x								x	
Middle (or Lower) Canyon (Large)					x														x					x			x	x
Middle Canyon (38 MW Version)																								x			x	
Middle Site										x														x			x	
Moon Lake + Tutshi River Outlet Site A Cluster																					x		x	x			x	
Moon Lake + Tutshi Windy Arm Outlet Site B Cluster																					x		x	x			x	
Moon Lake A																					x		x	x		x	x	

Knight Piésold CONSULTING

Reports	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Date	Aug-68	Jan-68	Dec-69	Feb-70	Jan-75	1977	Nov-80	Oct-80	Nov-80	Aug-81	Oct-82	Mar-82	Feb-82	Feb-82	Feb-82	Jun-82	Sep-82	Mar-83	Oct-83	Dec 1983	Dec 1984	Jun-05	Feb-08	Jan-10	Jan-11	Sep-14	Jan-15		Oct-16
Author	Department of Mines and	T. Ingledow & Associates Ltd.	Montreal Engineering	T. Ingledow & Associates Ltd.	Sigma Resource Consultants Ltd.	Montreal Engineering	Monenco Consultants Pacific	Shawinigan Engineering	Monenco Consultants Pacific	Shawinigan Stanley	Northwest Hydraulic Consultants Ltd.	Shawinigan Stanley	Acres Consulting Services Ltd.	SNC Consultants Ltd.	Crippen Consultants	Crippen Consultants	Monenco Consultants Pacific	Monenco Consultants Pacific	Monenco Consultants Pacific	A.S. Demers	A.S. Demers	(No Stated Author; Stewart)	KGS Group Inc.	AECOM Canada Ltd.	AECOM Canada Ltd.	Marc-Andre Lavigne	Midgard Consulting Inc.	Midgard Consulting Inc.	Knight Piesold Ltd.
Title	A Preliminary Appraisal of the Yukon-Taiya and Yukon-Taku Hydro-electric Resources Survey of the Yukon Territory	Northern Canada Power Commission - Francis River Power Survey of the Laird River Basin Yukon and Northwest	The Development of Power in the Yukon Mayo-Dawson District	Francis River - Upper Canyon Preliminary Study of a 26.2 M.W.	Mid-Yukon Feasibility Study, Year 1; Vol 1; Summary Report	Teslin River Hydro Power Study	Yukon Mining Hydro Power Study of Small to Mid- Size	False Canyon Hydro Prefeasibility Study: Mid-Study Report	Economic Studies of Five Hydro	False Canyon Hydro Prefeasibility Study	Granite Canyon Development Pre Feasibility Study	Preliminary Study of a Hydroelectric Site at Ross	Hoole Canyon Hydroelectric Project 1981 Site Investigation	Hoole Canyon Hydroelectric Project Investigations	Yukon Hydro Investigations Coordination Conclusions from	Northern Canada Power Commission Slate Rapids	The Inventory of Yukon Hydroelectric Sites - Review of	Yukon Energy Corporation: 1989 Hydro Investigations	Yukon Energy Corporation: 1980 Hydro Investigations	1991 Hydro Investigations	Assessment of Potential Hydroelectric Sites: Concept	2009 Large Hydro Stage 1: Initial Evaluation Draft Report	Preliminary Power Potential Assessment Rock Lake	EMAIL: Next Generation Hydro Project	Yukon Next Generation Hydro and Transmission Viability Study	Yukon Next Generation Hydro and Transmission Viability Study	YEC Small Hydroelectric Projects - Screening Assessment
Reports	1	2		3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Project Name																													
Moon Lake C																					X		X	X		X	X		
MoonLake B																							X	X			X		
Morley River																					X	X	X			X	X		X
North Fork Klondike River																						X					X		X
North McQuesten		X			X														X								X		X
NWPI (High)																								X			X		
NWPI (Low)		X			X			X											X					X			X	X	
Ogilvie					X														X					X			X		
Orchay																						X					X		X
Pleasant Creek		X			X														X			X					X		X
Pleasant Creek with Rogue Diversion		X			X																	X					X		X
Porcupine		X			X														X					X			X		
Porcupine Canyon					X														X					X			X		
Prevost Canyon		X			X														X	X							X		X
Primrose Diversion Scheme (To Takhini Lake)																				X							X		
Primrose Lake to Takhini Lake Diversion		X																	X								X		
Quartz Creek				X															X					X			X		
Quiet Lake Diversion		X			X														X								X		X
Quiet Lake Diversion + Rose River Diversion		X																	X								X		X
Rancheria																								X					
Reid Lakes and Lake Creek																													X
Rock Creek																													X
Rogue		X			X														X			X					X		X
Rose Creek																													
Rose Lake to Kusawa Lake Diversion		X			X														X							X	X		X
Ross Canyon		X			X			X			X			X			X		X	X			X				X		
Saucy Creek				X															X				X				X		
Seven Mile Canyon		X			X														X								X		X
Site 124																							X				X		
Site 127																							X				X		
Sixty Mile River Diversion		X			X														X			X					X		X
Slate Rapids (Diversion Scheme)																		X		X			X			X	X	X	
Slate Rapids (Powerhouse in Main Dam)																		X		X			X			X	X		
Squanga Creek																				X		X				X	X		X
Surprise Lake																													
Swede Creek																													
Swift																							X				X		
Swift River																							X				X		
Tatshenshini + Dezadeash / Kusawa Diversion					X														X								X		
Tatshenshini + Dezadeash Diversion					X																		X				X		
Tay River		X			X														X				X				X		
Tenas Creek (Orchay Diversion)																													
Thane Creek																													
Tootsee River																													X
Tutshi River Outlet Site A (Lake to Lake)																					X		X	X			X		
Tutshi River Outlet Site A (Lake to River)																					X		X	X			X		
Tutshi River Outlet Site A (River to Lake)																					X		X	X			X		
Tutshi River Outlet Site A (River to River)																					X		X	X			X		
Tutshi Windy Arm Outlet Site B (East PH)																							X	X			X		X
Tutshi Windy Arm Outlet Site B (West PH)																							X	X			X		
Two Mile Canyon		X			X														X					X			X	X	
Upper & Lower Primrose (2008 Layout)																				X	X		X	X			X		X
Upper Canyon (Large) -Francis River				X	X	X	X												X					X		X	X	X	
Upper Canyon (Medium) -Francis River				X	X	X	X												X					X		X	X	X	
Upper Canyon (Small) -Francis River				X	X	X	X												X					X		X	X	X	
Upper Canyon on White River		X			X														X								X		
Watson Lake																										X	X		X
Watson River		X			X																						X		X
Wind																								X			X		
Wolf River					X														X		X	X		X			X		X
Wolverine					X														X					X			X		
Yukon-Taiya	X				X														X					X			X		
Yukon-Taku	X				X														X					X			X		

M:\1\03\0055\05\08\A\Report\1 - Yukon Hydropower Potential Assessment (10-30 MW)\Rev 0\Appendix A\[Appendix A.xlsm]Table A.1

0	29NOV19	ISSUED WITH REPORT VG/AS&S-T	BJF	SGS
REV	DATE	DESCRIPTION	PREP'D	ROV'D

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)

APPENDIX B

Site Descriptions

(Pages B-1 to B-9)

APPENDIX B
SITE DESCRIPTIONS

The projects passing the coarse screen have been reviewed below and numeric details about each site can be found in **Error! Reference source not found.** of the main report. On occasion sites previously lacking information have been added to the Table for completeness or a further site-specific review revealed the site should be dismissed from consideration or added for consideration.

1.0 CLUSTER 1 – AISHIHIK-WHITEHORSE 138 KV

1.1 PRIMROSE

This site was short listed. See Section 7.1.

2.0 CLUSTER 2 – CARMACKS-WHITEHORSE 138 KV

2.1 IBEX RIVER

A concept for a 3.5 MW run-of-river on the Ibex River was investigated and dismissed based on size and cost. The site is a bit too far removed from transmission and access to be viable. It does benefit from a nearby stream gauge that could help in refining the energy generation assessment.

3.0 CLUSTER 3 – CARMACKS-FARO 138 KV

3.1 ANVIL

A few run-of-river configurations were considered up and down Anvil Creek. The project location has been previously been associated with Anvil Lake, a site that does not offer the same generating opportunities. The most attractive options for Anvil Creek assume long tunnels, resulting in average to higher LCOE returns, as such the project was not shortlisted. It was only possible to fully regulate the river for winter generation with a very tall dam structure, which proved to be cost prohibitive (i.e. $1 billion for 30 MW of firm winter generation).

3.2 DRURY

This site was short listed. See Section 7.2.

3.3 GLENLYON

Glenlyon offers the opportunity for a lake storage project or a run-of-river project but falls short of the desired installed capacity and is a bit too isolated and costly.

3.4 LITTLE SALMON

The Little Salmon Lake outlet offers little in the way of elevation differential given the current available topography. It is also not believed that it would be an environmentally acceptable site given its use for recreational angling and the name of the lake. It was elected not to consider the site for a high dam.

3.5 TAY RIVER

The Tay River forms a large watershed but it's existing WSC stream gauge indicates (perhaps inaccurately) a very low unit runoff (2.4 l/s/km^2). The gauge information also reveals the site offers a poor winter generation profile even at a low design factor. The site is also a bit too distant from transmission and access increasing its cost.

4.0 CLUSTER 4 - STEWART CROSSING - CARMACKS 138 KV

4.1 LAKE CREEK AND REID LAKES

Lake Creek offered the opportunity for an average run of river project. A Reid Lakes storage project could only be built with a diversion from Lake Creek (through the run of river project). Reid Lakes is a flat system of lakes that appear difficult to keep contained based on the available topographical observations; as a result, it is not able to provide full impoundment for winter generation limiting the concepts value.

Reid Lake was nevertheless a relatively interesting winter energy option, but when averaged with the inclusion of the Lake Creek cost and energy it fell off the project short list, particularly given the requirement for an interbasin transfer.

4.2 GRANITE CANYON

The Granite Canyon project site is located on the Pelly River, approximately 20 km east of Pelly Crossing. It is considered as a small run-over river project on a very large system, the total drainage area is estimated to be 46,200 km^2. The site proved one of the more difficult to evaluate at a very high level as the temporary works costs could outweigh the costs of the permanent works, but this is difficult to evaluate without a detailed assessment.

The Granite Canyon site was previously designed as a potential 254 MW hydroelectric project. The project first appeared in T. Ingledow & Associates Limited's report entitled "Hydroelectric Resources Survey of the Central Yukon Territory" in 1968 and subsequently revisited in Sigma Resource Consultants Limited's 1975 "The Development of Power in the Yukon" report.

KP has not had the opportunity to review the Acres Consulting Services Limited's (Acres) 1982 "Granite Canyon Development Prefeasibility Study" or the AECOM Canada Limited's 2010 "Large Hydro Stage 1" report. The Acres 1982 preliminary project layout included a large facility with a 100 m high concrete arch dam and a smaller 50 m high arch dam configuration with a crest gate spillway structure built into the dam. The water intake, conveyance, powerhouse, and tailrace structures were located on the west abutment of the river. Diversion tunnels were located under the east abutment of the river to facilitate de-watering of the dam site during construction.

KP's rapid assessment assumes a 25 m, concrete faced rockfill dam and a low design flow factor (0.25 x MAD). The initial cost estimate indicates that the project site had a low LCOE and a decent winter energy profile but was not short listed due to perceived social acceptability and permitting risks.

4.3 MICA CREEK

Taltmain Lake offers the ability to regulate the Mica Creek flows however we assume a low unit runoff for the area and there appears to be insufficient drop in elevation to justify a 10 MW project size.

5.0 CLUSTER 5: DAWSON CITY - STEWART CROSSING 69 KV

5.1 ALDER CREEK, BONANZA CREEK, FIFTEEN MILE DIVERSION, FORTY MILE RIVER AND INDIAN RIVER, SWEDE CREEK, AND THANE CREEK

These projects were evaluated on a run-of-river basis as they offered decent drainages or elevation drops but their assumed poor unit runoffs and a lack of winter generating potential make them unsuitable based on current assumptions.

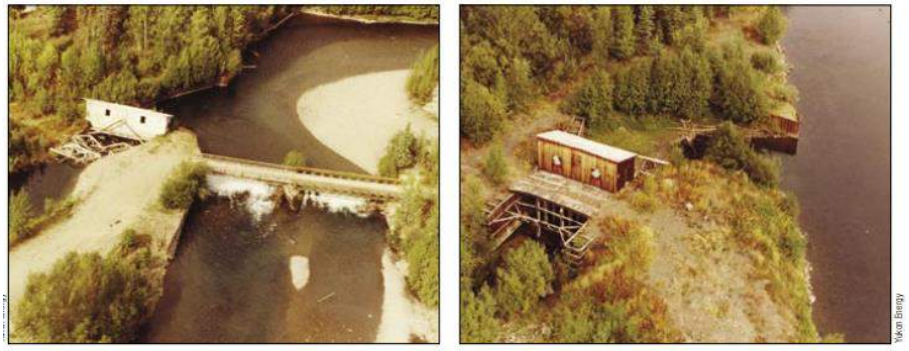
5.2 MCQUESTIN

McQuestin is a sizable river basin (3,769 km^2) and offered some promise as a small section of the river appears on the mapping to show a 60 m drop over a 9 km distance. The existing stream gauge on the river offered some certainty around the unit runoff. The cost estimate puts the project in a high but viable range for further consideration.

5.3 NORTH FORK KLONDIKE RIVER

A plant used to exist on the Klondike River at North Fork. YEC information reveals:

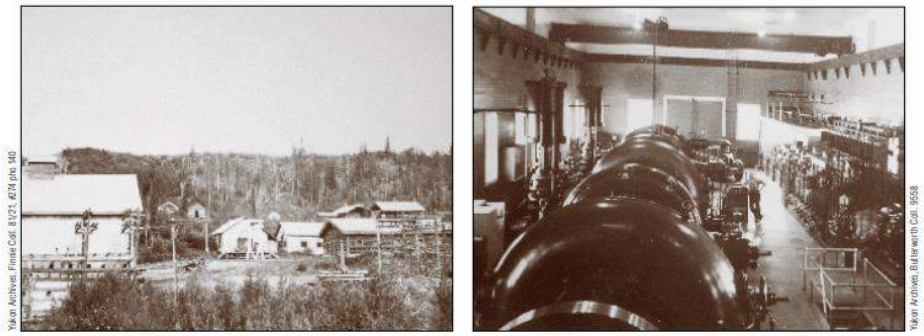
“The North Fork plant operated until 1966, when the last Yukon Consolidated Gold Company dredge shut down. A number of studies have been undertaken over the years to explore the feasibility of re-activating the North Fork plant. All have recommended against it, largely because of the difficulty of maintaining power production through the winter months when demand is the highest.”



NOTE:
1. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.1 North Fork Plant (Photos)

Yukon Energy Corporation
Small Hydroelectric Projects
Screening Assessment (10 MW – 30 MW)



Powerhouse at North Fork, (left) 1922 and (right) interior, 1913. In 1935, the building was extended to house a third unit.

NOTE:
2. SOURCE: HTTP:/ /WWW.ENERGY.GOV.YK.CA/PDF/POWER_OF_WATER.PDF

Figure 5.2 North Fork Plant (Photos)

For this review KP considered a 10 MW project with a 10 m dam on the Klondike River at North Fork, elevation was limited due to the presence of bridges and the Klondike Highway.

6.0 CLUSTER 6 - STEWART CROSSING - MAYO 69 KV

No sites investigated.

7.0 CLUSTER 7: PROPOSED MAYO TRANSMISSION EXPANSIONS

7.1 BIG KALZAS LAKE

Big Kalsas Lake offers the opportunity of a 10 MW project with storage and regulation on the lake for winter generation. The cost estimate reveals it is on the higher end of the LCOE.

7.2 FRASER FALLS

A project at Fraser Falls would likely backwater the Horseshoe Slough Habitat Protection Area.

The available topography does not currently allow the identification of any specific drop in elevation at the fall's location. As a result, the project configuration assumed a dam would be the only means of providing any elevation drop. Fraser Falls drain an area in excess of 30,000 km^2. The assumed project costs end up being very high due to the very large temporary work costs.

7.3 PLEASANT CREEK WITH ROGUE DIVERSION

A further look into the access and transmission distances gave reason to remove this site from consideration due to the very high access and temporary works costs.

7.4 SEVEN MILE CANYON

Seven Mile Canyon offer the opportunity for a low head run of river project with a 20 m high structure, but the remoteness and configuration of the project resulted in a higher LCOE.

8.0 CLUSTER 8: PROPOSED FARO TO WATSON LAKE

During the second stage of screening, it was elected not to short list projects along the proposed Faro to Watson route. Lapie and Ross Canyon were still considered due to there proximity to the existing YEC transmission line at Faro.

8.1 BIG CAMPBELL CREEK

The Campbell Creek site was listed in the 2010 AECOM report as “no defined scheme” with a report reference from a 1980 Moneco report. Midgard reviewed the two 1980 Moneco reports available, but neither mentioned the site. The Campbell Creek site was listed in the 1983 Moneco summary report with the statement “not yet studied”. Due to the lack of available site information, it was previously discarded by Midgard. KP had also considered Campbell Creek but Big Campbell Creek is the name of the actual location considered. The site offers the possibility of a 10 MW run of river, but with a high LCOE.

8.2 BLIND CREEK

Small sub 10 MW run of river project that benefits from Anvil Lake.

8.3 CAMPBELL CREEK

In adequate site, possibly confused with Big Campbell Creek in previous studies.

8.4 FALSE CANYON OR FRANCES RIVER (LOWER CANYON)

The site may have been referred to previously as Frances River (Lower Canyon).

False Canyon on the Frances River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 15 m structure would allow for a 15 MW facility.

8.5 FINLAYSON

The Finlayson River is a major tributary to Frances Lake and the Frances River, in the Liard River watershed. The Finlayson River Project is located adjacent to the Robert Campbell Highway and just upstream of Frances Lake, approximately 300 km to the northeast of Whitehorse. The project site was previously short listed by KP.

The current design concept involves a run of river diversion on Finlayson River downstream of the Wolverine River confluence with possible lake storage and flow regulation on Finlayson Lake and Wolverine Lake. The Finlayson site could function as a run of river project on its own merits due to the relatively large drop in elevation. The project could easily be staged as the added controls at Finlayson Lake and Wolverine Lake are distinct sites that simply add value to the run-of-river project.

The site was relatively attractive but was removed from consideration with the removal of the Faro to Watson Lake proposed line.

8.6 FORTIN LAKE DAM

The Fortin Lake site was evaluated as a 6 MW and 10 MW storage site. Its value lies in regulating the Pelly River Flows for the benefit of downstream generation sites. Based on available topography a 25 m structure should offer a large amount of storage without needing to construct multiple saddle dams.

8.7 FRANCIS RIVER (MIDDLE)

On the Frances River, near the Frances River bridge on HWY 4 a narrow portion of the river offers the opportunity for a low head run of river project. A 20 m structure would allow for a 15 MW facility.

8.8 HOOLE CANYON

Hoole Canyon on the Pelly River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the Robert Campbell Highway and the proposed transmission. A 25 m structure would allow for a 12 MW facility.

8.9 HOOLE CANYON + FORTIN LAKE DAM

If the two projects are combined, they offer a firmer winter generation profile for smaller individual installed capacities.

8.10 HOOLE RIVER

The Hoole River site was listed in the 2010 AECOM report but was cut due to having “no defined scheme”. Midgard’s review of all available previous studies revealed no other mention of the Hoole River Project. Due to the lack of available information on the site, it was previously discarded. For the purpose of this study a 12 MW project resulting from a low head 20 m structure is proposed.

8.11 HYLAND RIVER

Hyland River at the Hyland Canyon offer the opportunity for a dam and some drop river elevation. The project site is a bit removed from other infrastructure increasing the potential project cost.

8.12 LAPIE

Lapie is an attractive run of river site and is located close to exiting transmission at Ross River. This study did not evaluate the large number of design permutations that are possible to optimize this site, as the drainage area varies greatly as the potential intake is pushed upstream for greater project head.

8.13 LIARD CANYON

The proper evaluation of Liard Canyon suffers from some topographical and mapping uncertainty at the border between British Columbia and the Yukon. A more detailed look at the site revealed that it is likely that a dam structure would impact the community of Watson Lake, as such the project was removed from further consideration.

8.14 LITTLE RANCHERIA RIVER

The 2010 AECOM report references the 1990 Demers report as a source for the Little Rancheria River site. The Little Rancheria site was listed in the 2010 AECOM report (with no stated capacity or energy) but was cut due to being a “very distant site”. Midgard’s review reveals the Little Rancheria River site was subject to reconnaissance study only in 1990, and no sites were identified. Due to the lack of available site information, it was previously discarded.

The current evaluation assumes a run-of-river project could be developed at the site with a long penstock, but the project is rather distant from the proposed transmission.

8.15 ROSS CANYON

Ross Canyon on the Ross River offers the opportunity for a low head run of river project in a relatively restrained canyon, near the community of Ross River. A 40 m structure would allow for a 15 MW facility. The site was looked at with a long conveyance system in lieu of a large dam but the capital cost would have increased. The site was removed from further consideration to a perceived lack of social licence. The project would also affect Canol Road #6.

8.16 SLATE RAPIDS

Slate Rapids as previously designed, is a potential 42 MW hydroelectric project on the Pelly River, located in the Pelly River Basin approximately 75 km east of the community of Ross River. The project first appeared in Moneco Consultants Pacific Limited’s report entitled “Slate Rapids Hydropower Development” in 1983. It was subsequently revisited in A.S. Demers’ 1989 “Yukon Energy Corporation: 1989 Hydro Investigations”, and in AECOM Canada Limited’s 2010 “Large Hydro Stage 1” report.

Given the range of projects considered 10-30 MW and the fact the Slate Rapids site was difficult to contain requiring multiple saddle dams, the use of Fortin Lake with a smaller structure seemed to be a better option for consideration.

8.17 TYERS RIVER

Tyers River is large drainage tributary of Frances Lake and offers the opportunity for a run of river project, but it is a bit removed from major infrastructure.

9.0 CLUSTER 9 - PROPOSED BEAVER CREEK TO HANES JUNCTION

9.1 LOWER CANYON ON WHITE RIVER

The Lower Canyon on White River is located immediately upstream of the Alaska Highway #1 White River Bridge. The area offers a narrowing of the glacier fed river, creating the potential for a 25 m structure and a 15 MW project.

9.2 DONJEK RIVER

KP Considered a low head run of river project on the Donjek River, it has very similar characteristics to the White River project but with the added costs of being more distant from the proposed transmission line and existing roads. It does drain a slightly larger area.

9.3 KOIDERN

The Koidern Project is a proposed glacier fed run-of-river hydropower development located between Haines Junction and Beaver Creek in southwestern Yukon. The Koidern River is a tributary of the Kluane River. The proposed powerhouse location is within 5 km of the Alaska Highway. It was selected as it is indicative of a more compact and cost-effective type of run-of-river project. It offers lower LCOE despite not offering any dependable capacity.

The project location is outside the bounds of the Asi Keyi Territorial Park, but the intake structure is proposed within the bounds of the Kluane Wildlife Sanctuary. The powerhouse is located outside the area bounds. It is not believed that this particular type of run-of-river development would be in conflict with the objectives of these protected areas, chiefly:

- To provide economic opportunities for Kluane and White River First Nation people.
- To recognize and protect the traditional and current use of the area by Kluane and White River First Nation people.
- To encourage public awareness, appreciation and enjoyment of the natural, historical and cultural resources of the park in a manner that will ensure it is protected for the benefit of future generations.
- To protect, for all time, a natural area of territorial significance, which includes a portion of the Kluane Wildlife Sanctuary, containing physical and biological features of international significance as well as sites of archaeological, historical and cultural value.

It is understood that the management planning for these areas began in April 2015 and is ongoing and that the Government of Yukon and the two affected First Nations will jointly review the plan before it is approved by Yukon's Minister of Environment.

A basic arrangement for the proposed project layout is shown on **Error! Reference source not found.**. Key project parameters for this layout are as follows:

- Design Flow: 16.4 m^3/s
- Gross Head: 140 m
- Installed Capacity: 16 MW
- Dependable Capacity: 0 MW (This project is a glacier fed run-of-river project and does not offer much in the way of winter generation)
- 10 km of access roads, to reach the powerhouse, penstock, and intake
- A run-of-river intake with a small headpond (El. 930 masl.)
- A 7 km long penstock.
- A Powerhouse and tailrace (El. 790 masl)
- A Substation and 20 km long transmission line to a potential transmission line along the Alaskan Highway

9.4 LYNX AND WOLVERINE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.5 BURWASH

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

9.6 DUKE

Like Koidern, the site offers the opportunity for a high head freshet driven run of river project.

10.0 CLUSTER 10: WHITEHORSE-CARCROSS-JAKE'S CORNER-JOHNSON'S CROSSING-TESLIN 34KV

10.1 SQUANGA CREEK

A development at Squanga Creek would not meet the 10 MW criteria threshold.

10.2 WOLF RIVER

This site was short listed. See Section 7.5.

11.0 CLUSTER 11: PROPOSED EXTENSION FROM CARCROSS TO SKAGWAY

11.1 MOON LAKE

Moon Lake is located roughly 100 km south-southeast from Whitehorse, and 18 km south of the BC Yukon border, and it drains into Tutshi Lake from the south and is ultimately a tributary to the Yukon River, above Whitehorse. While the site was attractive site that had been previously reported in some detail and offered storage capability but was below 10 MW in capacity at a design flow of 2.2 x MAD. The project would also be too small to support a transmission line to Carcross on its own merit.

11.2 TUTSHI LAKE

This site was short listed. See Section 7.3.

12.0 CLUSTER 12 - PROPOSED EXTENSION FROM JAKE'S CORNER TO ATLIN

12.1 SURPRISE LAKE AND THE ATLIN HYDRO PROJECT

This site was short listed. See Section 7.4.

Appendix F:
Knight Piesold Pumped Storage Report

Knight Piésold CONSULTING

November 27, 2019

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Mr. Hector Campbell
Chair, NNDDC Board
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Dear Hector,

RE: Moon–Tutshi Pumped Storage Options

1.0 INTRODUCTION

1.1 REQUEST FOR INFORMATION

YEC (Yukon Energy Corporation) has requested Knight Piésold (KP) to add the Moon-Tutshi pumped storage project to the short-listed sites for its report "Hydropower Potential Assessment (10 MW – 30 MW)". This letter report has been prepared to provide the relevant information for the Moon-Tutshi pumped storage project separately, as the assessment parameters and characteristics of the proposed pumped storage development are not easily comparable to a traditional hydropower project and are best presented in a separate report.

As requested, KP modeled the proposed Moon-Tutshi Pumped Storage Project, assuming the following development options:

- 15 MW installed capacity and 25 GWh/yr of continuous winter generating capability
- 15 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 25 MW installed capacity and 50 GWh/yr of continuous winter generating capability
- 35 MW installed capacity and 50 GWh/yr of continuous winter generating capability

1.2 PURPOSE

The proposed purpose of the Moon-Tutshi Pumped Storage Project would be as follows: a pump storage project between Tutshi Lake and Moon Lake designed to seasonally store freshet energy from other Yukon hydropower assets and provide additional winter generation potential to YEC. A pumped storage project would also provide greater flexibility within the YEC grid to allow for easier integration of solar and wind renewables.

1.3 PROJECT SITE AND BASIC CONCEPT

Moon Lake is located in British Columbia (BC) approximately 100km south of Whitehorse, and 20 km south of the BC-Yukon border. Moon Lake drains into Tutshi Lake through Moon Creek at a steep gradient. Existing mapping shows an approximate 390 m drop in elevation between the two lakes. Tutsh Lake drains into Tagish Lake and onwards to the Yukon River.

The Klondike Highway linking Carcross Yukon and Skagway Alaska runs along the western shore of Tutshi Lake. Accessing the Moon Lake site will require either a barge or a new road. If a barge is used, new barge

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landings will need to be constructed at a point along the Klondike Highway and at the foot of Moon Creek. If a new access road is constructed, the shortest and most practical route would be along the southern shoreline of Tutshi Lake.

The 2015 study by Midgard of a proposed pumped storage project at Moon-Tutshi Lakes assumes that flows from Tutshi Lake are pumped into the Moon Lake storage reservoir during high flow - low energy demand periods. The Midgard study had not accounted for a new structure at the outlet of Tutshi Lake, which has now been included. Access to the outlet of Tutshi Lake would require either a new 20 km access road from the Klondike Highway or a new barge landing and access road from Tagish Lake. (See Figure 1.1.)

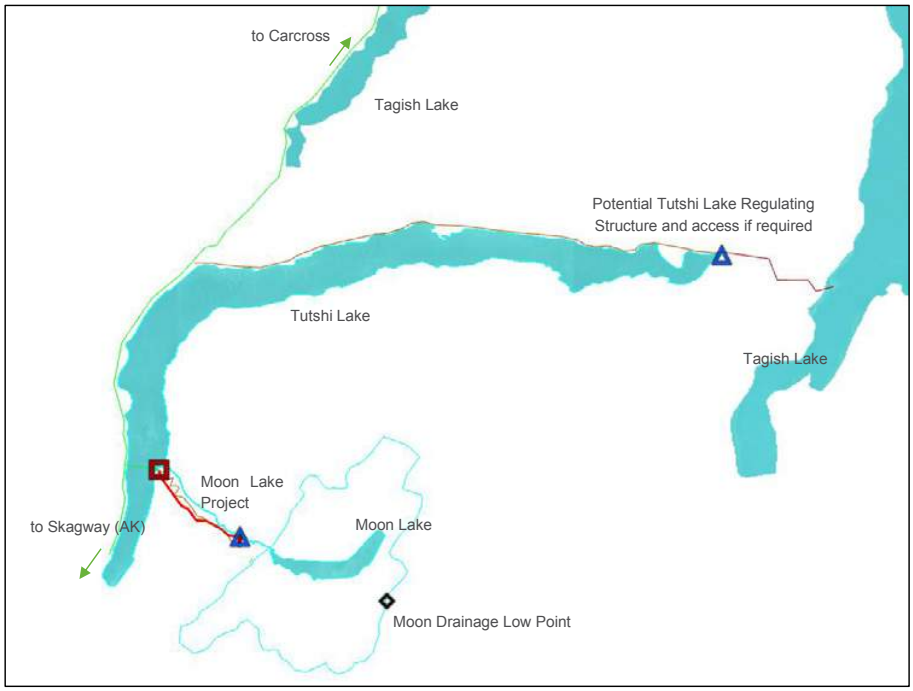


Figure 1.1 Tutshi-Moon Project

The proposed pumped storage project will create a large reservoir for storage on the existing Moon Lake and draw flows as need for generation from this new Moon Lake Reservoir. Water stored in the Moon Lake reservoir will come for two sources, including:

- Natural inflows into the reservoir from the Moon Creek catchment
- Pumped water from the lower Tutshi Lake

The Tutshi Lake/T'ooch' Áayi Conservancy was established in 2012 as a result of the Wóoshtin Wudidaa Atlin Taku Land Use Plan and Taku River Tlingit First Nation Strategic Engagement Agreement. The

conservancy, located approximately 65 kilometres northwest of Atlin, encompasses the eastern half of Tutshi Lake. Tutshi Lake is culturally significant to the Carcross/Tagish and Taku River Tlingit First Nations. The lake also has high value lake trout habitat. The Tlingit name (T'ooch' Áayi) means "charcoal lake", after the dark colour of the lake water. Moon Lake is not located within the conservancy, but the outlet of Tushi Lake is.

2.0 CONFIGURATIONS

2.1 PREVIOUS

The 2015 Midgard report proposed a project arrangement comprising the following key components:

- a 31 m high, 700 m long earthfill dam on Moon Lake with a spillway on the south abutment of the dam.
- a low level outlet/intake in both Moon Lake and Tutshi Lake.
- a 5.24 km long, 1.6 m diameter buried steel penstock.
- a powerhouse, with concrete substructure and steel superstructure, containing a 20.2 MW vertical axis Pelton turbine and synchronous generator as well as two 9.4 MW peak power, variable speed drive vertical axis pumps. Flows would be discharged to or drawn from a 7 m deep sump connected to Tutshi Lake.

2.2 PROPOSED

For the purpose of this assessment the layout of the proposed Moon-Tutshi Project has been assumed to be comparable to the Midgard layout, but with differing storage capacities and generation capacities. The Moon Lake dam location and powerhouse location were assumed to be identical; the penstock was assumed to be run on the left bank. The penstock alignment was changed slightly for a more manageable access gradient shortening it by 250m for a total 5km length. These concepts should be further refined if the project is advanced.

The project characteristics for the different development options are presented in Table 2.2 below. The pumping durations presented below were determined based on preliminary modeling of the hydrological system and could be increased in size if desired (i.e. to provide additional flexibility for YEC's Grid for the addition of more renewables such as wind and solar).

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Table 2.1 Moon-Tutshi Project Attributes

	Moon-Tutshi Pumped Storage			
	15 MW	15MW	25MW	35MW
	25 GWh	50 GWh	50 GWh	50 GWh
Moon Lake Minimum Operating Level (masl)	1,114	1,114	1,114	1,114
Moon Full Supply Level (masl)	1,121.5	1,124	1,124	1,124
Tutshi Lake Tail Water Level (masl)	714	714	714	714
Active Storage Variation (m)	7.5	10	10	10
Total Dam Height (m) (assuming 3 m of overburden and 4 m of dead storage and 1 m freeboard)	15.5	18	18	18
Active Storage Volume ($x10^6$ m^3)	40	59	59	59
Design Flow - Generation (m^3/s)	4.4	4.4	7.35	10.25
Design Flow - Pumping (m^3/s)	1.0	3.0	3.0	3.5
Installed Capacity (MW)	15	15	25	35
Full to Empty Energy Storage (GWh)	38	56	56	56
Generation Duration to Empty Reservoir (Days)	106	156	93	67
Pumping Duration to Fill Reservoir (Days)	460	228	228	196
Average Annual Generating Energy (GWh)	33.4	51.8	54.7	59.1
Minimum Annual Generating Energy (GWh)	25.2	47.6	46.2	51.2
Average Annual Pumping Energy (GWh)	14.8	39.5	44.6	51.2
Average Annual Net Energy (GWh)	18.5	12.2	10.1	7.9
Average Whitehorse Hydro Plant Bonus Winter Yield (GWh) based on 140 kW per m3/s	1.4	1.8	1.9	2.1
Average Total Net Energy (GWh)	19.9	14.0	12.0	9.0

3.0 HYDROLOGY AND ENERGY ASSESSMENT

KP assessed the hydrology of both the Moon Lake and Tutshi Lake catchment areas and then developed a daily energy model using the parameters presented in the sections below (Sections 3.1. through 3.6).

3.1 HYDROLOGY

For the purpose of this study, more effort was placed on the assessment of the Moon Lake catchment area, as it is small when compared to the Tutshi Lake catchment area and would therefore be the more critical water resource in terms of the pumped storage hydro assessment. The natural inflows into Moon Lake would also contribute to the energy generation potential of the project, and therefore have a direct impact on the financial viability of the project.

Moon Creek has a drainage area of 57.4 km^2 at the proposed dam on Moon Lake. The existing WSC data shown in Table 3.1 was utilised to determine long-term daily inflows into Moon Lake averaging out to 0.8 m^3/s.

Table 3.1 Stream Gauges

Gauge	WSC	Period	Drainage Area (km^2)	Unit Runoff (l/s/km^2)	Complete Years
Moon Creek near the outlet of Moon Lake	09AA018	2012-2017	53	13.5	4
Tutshi River at outlet of Tutshi Lake	09AA013	1956-2017	989	16.2	50

3.2 TUTSHI LAKE STAGE DISCHARGE RELATIONSHIP

For the purpose of this evaluation is was assumed that the Tutshi Lake elevation is naturally maintained at 1,114 masl. This is not an unreasonable assumption given the relative size of Tutshi Lake compared to Moon Lake.

If this project is advanced to the next stage, it is recommended that existing WSC data be utilized to develop a Tutshi Lake stage discharge curve to simulate the natural control of the lake outlet and then perform the appropriate water balance to determine if there is any significant fluctuation in the Tutshi Lake levels that might impact the energy and power generation potential of the proposed project.

3.3 CYCLE EFFICIENCY

A traditional pumped storage hydroelectric project has a roundtrip efficiency of about 70% (i.e. consumes 30% more energy than it generates). As per the previous studies by KP and Midgard, the same 30% losses have been assumed for the Moon-Tutshi Project. This equates to a combined hydraulic, electrical and mechanical efficiency of 87% while generating and 81 % while pumping for the 15 MW, 25 GWh option.

3.4 YEC SYSTEM BENEFIT

YEC has advised KP that the average winter water to kW conversion at the Whitehorse Hydro Plant is 140 kW per m^3/s. The expected additional annual winter energy yield is shown in Table 2.2.

3.5 STORAGE

For the purpose of this assessment the depth area capacity relationship (DAC) provided by the Midgard has been used in the assessment. The corresponding active storage volumes are shown in Table 2.2.

3.6 OPERATING RULES

The Moon Lake Reservoir is operated on a continual generation basis to the extent possible during the months of November-February or if the reservoir is over 95% full. Pumping is triggered in the months of June-September until the reservoir is 95% full. An instream flow release (IFR or ecological flow) of 5% of the Mean Annual Discharge (MAD) is continually released from the Moon Lake Reservoir to sustain the aquatic habitat in Moon Creek.

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3.7 ENERGY ASSESSMENT

A daily flow energy model was developed for the system that accounted for both the pumped flow into Moon Lake plus the natural inflow into Moon Lake. This makes the Moon-Tutshi Pumped Storage Project somewhat unique, as for all four options for the project are net energy generators (i.e. not consumers like traditional closed loop pumped storage hydro facilities). Table 2.2 presents the results of the study, including:

- Energy required for pumping
- Energy generated from a combination of the pumped flows and natural inflows
- Energy generated through benefits to the YEC grid
- Total Net Energy (GWh/year)

4.0 COST ESTIMATE

The capital cost estimates shown in Table 4.1 are based on the project configurations described in Table 2.2 above. These basic project characteristics were used to establish the sizes of the project components and associated quantities. These technical attributes were used to estimate approximate material volumes for excavation, backfill, embankment material and reinforced concrete. Electrical and mechanical equipment requirements were estimated based on empirical data from KP's prior projects and published reports. The capital cost estimate includes an allowance for the Contractor's preliminary and general costs (overheads, insurance, bonus and profit etc.), an allowance for EPCM costs, and a variable contingency.

Unit rates for material production, equipment procurement and installation costs relied on KP's internal costing database including recent, relevant experience with similar sized hydroelectric projects in Western Canada and the Yukon Territory. KP's hydro project cost database also offered an "order of magnitude check of total estimated costs for individual facility components and complete facilities, based on projects with comparable characteristics such as, design flow, penstock pipe characteristics (length, diameter, etc.), gross head, generating capacity, powerhouse area, excavation quantities, reinforced concrete volumes, backfill quantities, switchyard capacity and transmission line capacity and length. Generating equipment costs are based on installed capacity, head and flow, while switchyard costs are interpolated based on installed capacity.

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Table 4.1 Cost Estimate

	Tutshi-Moon			
	15 MW	**15MW**	**25MW**	**35MW**
	25 GWh	**50 GWh**	**50 GWh**	**50 GWh**
Mod, Demob, Insurance, Bonds, Overheads, Contractor's Profit	$30,500,000	$32,500,000	$41,000,000	$46,800,000
Access and Site Preparation	$6,000,000	$6,000,000	$6,000,000	$6,000,000
Intake, Forebay, and Headrace	$3,200,000	$3,200,000	$4,500,000	$5,700,000
Water Conveyance System	$25,000,000	$25,000,000	$37,500,000	$43,400,000
Powerhouse and Ancillary Services	$11,000,000	$11,000,000	$15,500,000	$18,000,000
Power Generation Equipment (Water to Wire)	$15,000,000	$15,000,000	$25,000,000	$35,000,000
Switchyard, Transmission and Interconnection	$4,000,000	$4,000,000	$4,000,000	$4,000,000
Dams and Reservoirs	$22,500,000	$29,000,000	$29,000,000	$29,000,000
Access and Dam on Tutshi	$15,000,000	$15,000,000	$15,000,000	$15,000,000
Sub-Total	$132,200,000	$140,700,000	$177,500,000	$202,900,000
EPCM	$10,600,000	$11,300,000	$14,200,000	$16,200,000
Contingency	$39,700,000	$42,200,000	$53,300,000	$60,900,000
Total Estimated Capital Cost	**$182,500,000**	**$194,200,000**	**$245,000,000**	**$280,000,000**

NOTES:
1. 2019 CANADIAN DOLLARS (CAD)
2. DOES NOT INCLUDE UPFRONT ENVIRONMENTAL, PERMITTING AND OWNERS COSTS.
3. DOES NOT INCLUDE APPLICABLE SALES TAXES.
4. EPCM COSTS INCLUDE DETAILED ENGINEERING, TENDERING OF CIVIL AND WATER-TO-WIRE CONTRACTS, SITE SUPERVISION, OVERALL PROJECT MANAGEMENT AND ENVIRONMENTAL MONITORING.
5. COSTS ARE PRELIMINARY AND ARE CONSIDERED EQUIVALENT TO AN AACE CLASS 5 ESTIMATE.

5.0 RECOMMENDATIONS

It is recommended that the Taku River Tlingit First Nation and Carcross Tagish First Nation be consulted prior to any serious consideration of the project development. There may be traditional use and cultural values associated with the site that this study does not take into consideration. A more detailed review of site-specific data would be required to confirm project viability and the optimal project size.

Further evaluation of the site is recommended, to improve the design basis, the project configuration, and the understanding of hydrological, topographical and geotechnical conditions. The following activities are recommended:

- Set the project's energy objectives, including the required installed capacity and winter energy generation requirement with a clear purpose for how the plant is envisaged to be utilised.
- Perform a more detailed review of the existing hydrological information.

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- Obtain accurate topographical mapping for the proposed project area to confirm project configurations and details including dam sizes, water conveyance routings, available generation head, powerhouse locations, access roads, and transmission lines. For this project site a LIDAR survey is highly recommended. KP can aide in solicitating contractors to this effect.
- Several existing rights have been previously been identified at the project site and its vicinity. These should be investigated further in order to make sure all potential development barriers have been mitigated.
- Submit a water licence application to Front Counter BC so as to secure the first-in-line water rights to the project ahead of other potential claimants. British Columbia recognizes the rights to water on a first come, first serve basis.
- Complete a feasibility level assessment of the project, including environmental screening.

6.0 CLOSING

Should you require any additional information or clarification on the content of this report, please do not hesitate to contact either of the undersigned.

Yours truly,
Knight Piésold Ltd.

PROFESSIONAL ENGINEER
PROVINCE OF BRITISH COLUMBIA
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Approval that this document adheres to the Knight Piésold Quality System: SRM

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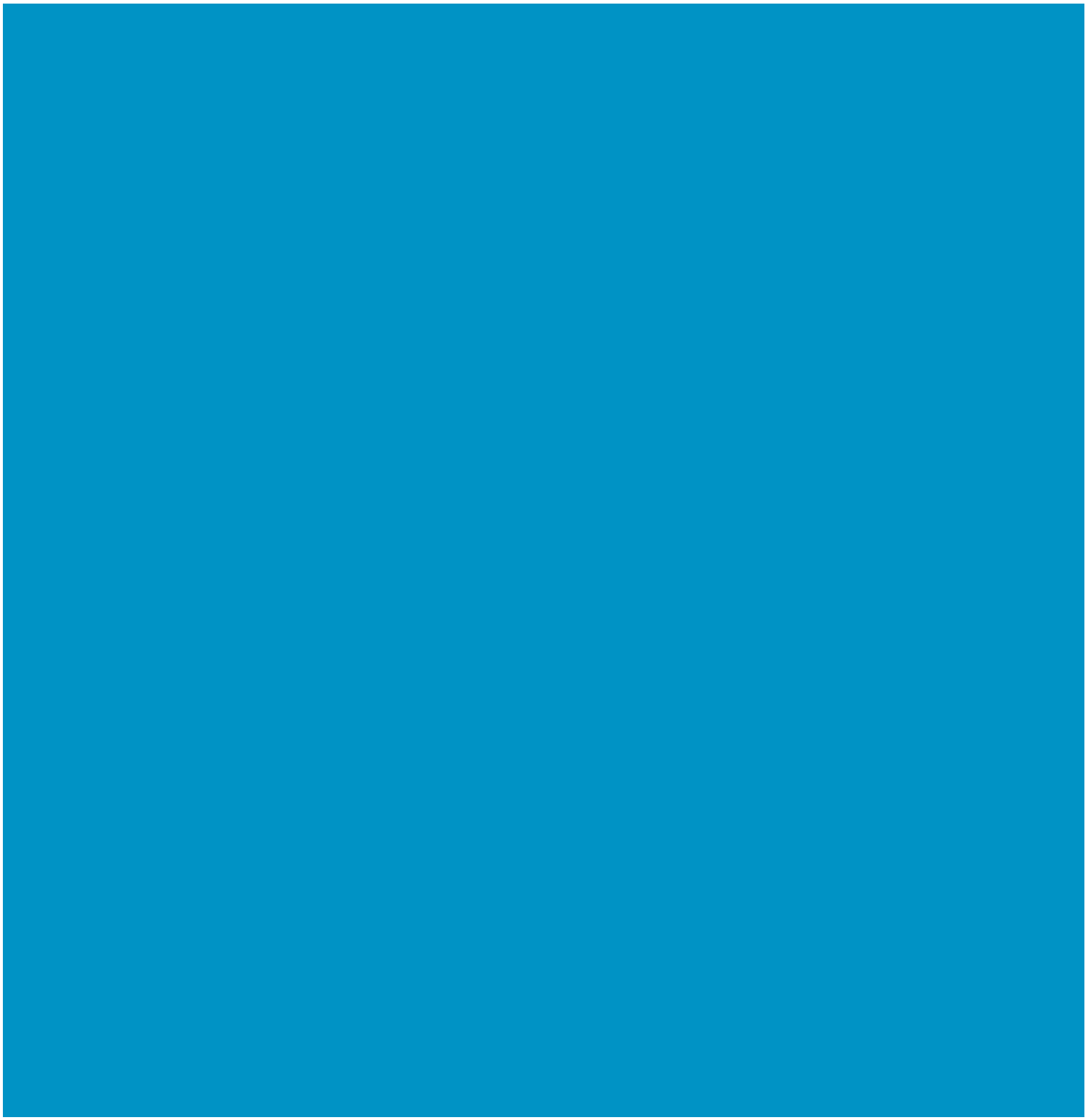
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YUKON UTILITIES BOARD

Report to Yukon Minister of Justice

Yukon Energy Corporation Application for Energy Project Certificate

and Energy Operation Certificate

Regarding the Proposed

Battery Energy Storage System (BESS) Project

June 30, 2021

1. INTRODUCTION

On December 17, 2020, the Government of Yukon designated the Yukon Energy Corporation's (YEC's) proposed Battery Energy Storage System Project (BESS Project) as a regulated project under Part 3 of the *Public Utilities Act*.[1] On January 21, 2021, YEC filed an application for an energy project certificate and an energy operation certificate for the BESS Project (Application) with the Minister of Justice (Minister).

In a February 2, 2021 letter, the Minister referred the Application to the Yukon Utilities Board (Board) for a review and hearing pursuant to Part 3 of the *Public Utilities Act*. The letter included Terms of Reference, which set out the purpose and the specific aspects of the BESS Project to be reviewed, and stipulated that the Board hold a public hearing and submit its report and recommendations to the Minister no later than May 17, 2021.

On March 10, 2021, the Board requested that the Minister extend the reporting deadline to the end of July 2021. The Minister responded to the Board letter on April 16, 2021 and, pursuant to section 41(1) of the *Public Utilities Act*, granted the Board's request and required the Board to provide a report with its recommendations by June 30, 2021.

On February 18, 2021, the Board issued Board Order 2021-03, which gave notice of the Application, set out the process schedule for the Application up to the submission of intervener evidence, and stated that further process would be determined after April 9, 2021. Board Order 2021-03 also requested that parties intending to participate in the proceeding register in writing with the Board by March 1, 2021.

The Board received requests for intervener status from ATCO Electric Yukon (AEY), the Utilities Consumers' Group (UCG), the Yukon Conservation Society (YCS), and from John Maissan. All requests for intervener status were granted.

The Board issued further Board Order 2021-06 on April 16, 2021, which established the remaining process schedule, including the opportunity for the public to provide written comments on the Application by April 30, 2021. Board Order 2021-06 also set the virtual oral hearing process. The Board issued correspondence on April 27, 2021 providing the protocol for the virtual hearing.

All interveners were provided the opportunity to submit information requests (IRs), file evidence, cross-examine the YEC witnesses, and provide final submissions. No comments were received from the public on YEC's Application by the April 30, 2021 deadline.

Board comments on the timing of the Application

YEC's Application was submitted to the Board by the Minister on February 2, 2021 with the expectation that the Board complete its report by May 17, 2021. YEC supported that deadline by stating that work on the BESS Project must commence by the summer of that year.

[1] Order-In-Council 2020/180 – Designating the Battery Energy Storage System Project as a Part 3 *Public Utilities Act* regulated project.

The Board is concerned with short deadlines for Part 3 applications. Board members serve on a part-time, volunteer basis, with contracted supporting resources. The Board requires sufficient time to discharge its mandate, considering these constraints. For example, the established metric for this Board to produce a report or major decision is generally 90 days from the close of record. In this case, a general rate application (GRA) was already in front of the Board when the Minister imposed its timeline for this Part 3 application proceeding, raising additional resourcing concerns. In addition, the Board is concerned that a short deadline for a Part 3 application may not allow sufficient time for the administrative and regulatory procedures necessary to effectively and fairly process a Part 3 application.

For future Part 3 applications, YEC is expected to build time into the regulatory schedule for the Minister to review and refer the application to the Board and to provide a reasonable time period for any public sessions, a sufficient time period for record development before the Board, and 90 days for the decision report. Sufficient time for the review, referral, and Board hearing process allows for procedural fairness to parties to the proceeding and protects the integrity of the regulatory process. A shortened timeline should only be allowed in exceptional circumstances.

2. OVERVIEW OF THE APPLICATION

In its Application, YEC stated that the BESS Project consists of a containerized lithium ion battery energy storage system on a 1.5 hectare site that YEC will lease on undeveloped Kwanlin Dün First Nation (KDFN) Category B settlement land located northeast of the intersection of Robert Service Way and the Alaska Highway in the City of Whitehorse.

The BESS will be connected to the YEC Whitehorse Rapids facility by a new 1.7 kilometre, 34.5 kilovolt (kV) transmission line that runs north of the KDFN site, following existing easements through forested Crown land until it meets and follows the path of an existing AEY 34.5 kV line to the Whitehorse Rapids facility.

The proposed BESS Project involves a grid-sized BESS with 40 MWh of useful energy storage capacity and 20 MW of inverter and transformer capacity that together will provide 7.2 MW of dependable capacity to the Yukon Integrated System (YIS) for 20 years, starting in the winter of 2022-23.

YEC expects that 7.2 MW of dependable capacity provided by the BESS Project will reduce the need to rely on rental of diesel generators during the winter months and will displace four 1.8 MW diesel rental units to address capacity shortfalls. YEC argued that the BESS Project will also provide other benefits, including: operating reserve that reduces thermal generation requirements; enhanced black start capability; and opportunities for diesel peak shifting.

The BESS Project lies within the overlapping traditional territory of the Ta’an Kwäch’än Council (TKC) and KDFN. YEC stated that it engaged with both First Nations in Q2 of 2020 to form a trilateral committee for sharing BESS Project information and assessing three potential KDFN and TKC sites for the BESS Project. The BESS Project includes a debenture investment opportunity for both TKC and KDFN.

The preliminary capital cost estimate (in 2020 dollars, with a +/- 30% accuracy) for the BESS Project is $31.7 million. After $16.5 million in funding from the Government of Canada's Investing in Canada Infrastructure Program ("ICIP"), the preliminary net capital cost estimate to be borne by ratepayers is estimated at $15.2 million.[2]

3. TERMS OF REFERENCE

The Minister stated that the general purpose of the review and hearing of the Board was to "obtain the YUB's report and recommendations on the potential benefits, costs, risks and customer impacts that influence whether the BESS Project should proceed as proposed by YEC, and any terms and conditions which the YUB considers should apply."[3] In the Terms of Reference, the Minister requested that the Board review the following specific aspects of the BESS Project:

> The YUB shall report on, and make recommendations about, the necessity for the BESS Project and its timing and design, with particular regard to:
>
> a. The public need for the BESS Project under various reasonable electric load forecasts, including near term requirements related to industrial and nonindustrial loads, and the effect of the project on the rates of customers and the reliability of electricity service provided to customers.
>
> b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria and the effect of the BESS Project on this capability.
>
> c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.
>
> d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments.
>
> e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping Traditional Territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.
>
> f. Whether it is prudent to build the BESS Project as proposed at this time.[4]

The Minister stated that the Board shall provide a recommendation on whether YEC should be granted an energy project certificate and an energy operation certificate for the BESS Project and whether the certificates should be subject to any terms and conditions. The Minister also added

[2] YEC Application, PDF page 7.
[3] Minister of Justice's BESS Terms of Reference, February 2, 2021, PDF page 2.
[4] Minister of Justice's Terms of Reference, February 2, 2021, PDF pages 2 and 3.

that the Board may make any other recommendations or provide any other information that it considers advisable in the circumstances.

3.1 Public Policy and Ratepayer Costs

During the proceeding, YEC stated that its board of directors made the decision to not pursue a permanent thermal plant and instead to focus on renewable projects. YEC also stated that its board of directors has a deliberate strategy that the major capital projects, such as the BESS Project, are to involve economic opportunities for First Nations. Siting the BESS Project on settlement land was referenced as a mechanism to achieve that goal. As proposed, the BESS Project triggers public policy considerations that are in the jurisdiction of government.

The Board's recommendations for the BESS Project are based on the Board's jurisdiction under Part 3 of the *Public Utilities Act*, which gives the Board the authority to make recommendations about the approval of the energy project certificate and the energy operation certificate for a facilities project in Yukon. After receiving the Terms of Reference from the Minister, the Board holds a hearing and prepares its report, which includes any recommendations of the Board. The Board can recommend that the Minister approve the project, deny the project, or approve the project with conditions.

The Board is an administrative tribunal established by the Government of Yukon, responsible to ensure that the utility services in Yukon take place consistent with the public interest. The Board is an economic regulator that determines just and reasonable rates for Yukon utilities within its jurisdiction.

As part of discharging its mandate under the *Public Utilities Act* and considering the Minister's Terms of Reference for the BESS Project, the Board must look at the need for the project, the impact of the BESS Project, the cost implications to ratepayers, and system reliability.

The Board is not allowed to consider public policy that is beyond its mandate, such as climate action or the government's direction to advance economic development for First Nations. There may be externalized economic costs and benefits of these public policy considerations, but these items are not within the Board's determinations to be made under the Terms of Reference.

The BESS Project is proposed as part of a larger renewable electricity strategy to address climate change by reducing fossil fuel use, and may result in higher costs to the ratepayer than more traditional energy options. Similarly, the choice to require siting of the proposed project on First Nation land, including a sole-sourced investment opportunity, may also result in ratepayer impacts.

A portion of the total cost of the BESS Project will be covered by funding from the federal government. YEC confirmed in testimony that the focus of its board of directors, flowing from the policy direction of the territorial and federal governments, is on renewable energy. It is worthwhile for the Minister to consider how much of a project should be financed through government and paid for by the taxpayer and how much should be financed by ratepayers through utility rates if a proposed project seeks to achieve public policy goals.

The role of YEC, as a regulated utility, is to provide safe, reliable, and cost-effective energy services. In this case, YEC argues that, as proposed, there is an economic benefit to ratepayers of the BESS Project compared to the alternative it put forward, which is the current practice of renting diesel generators to meet capacity shortfalls.

However, as the project economics are based on preliminary estimates with many outstanding agreements, including battery procurement, land leasing, and the investment opportunities for the TKC and KDFN through debenture agreements, there will be variability in the actual costs from what is presented in the current Application and reviewed by the Board. The BESS Project, as a proposed renewable facilities project under Part 3 of the *Public Utilities Act*, attracts risk. Ultimately, ratepayers could bear the cost in excess of a least cost or more proven, conventional alternative.

The Board recommends that, if there is Ministerial approval of this project, there should be comment on the public policy issues considered with regard to climate change and First Nation economic development opportunities, as there are real cost drivers stemming from these public policy issues. This is particularly important because actual costs of the project after it is approved by government could be disallowed by the Board during its prudency review in a future GRA. Disallowed costs are ultimately paid by taxpayers and not YEC's customers, the ratepayers.

In response to Board questions during the hearing, YEC stated that, if there is a premium to going green, its approach is to pursue federal funding to reduce the costs of the BESS Project to ratepayers. As stated above, the consideration of the benefits expected from First Nation economic development, or from reductions in greenhouse gas emissions, are not factors which the Board can consider within its mandate.

4. NECESSITY FOR THE BESS PROJECT

4.1 Public Need for the BESS Project — Term of Reference 3.a.

In the Terms of Reference, the Minister requested the Board to report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> 3.a. The public need for the BESS Project under various reasonable electric load forecasts, including near term requirements related to industrial and nonindustrial loads, and the effect of the Project on the rates of customers and the reliability of electricity service provided to customers.[5]

Yukon Energy Corporation

YEC provided a 2021-2030 forecast non-industrial peak load and a forecast dependable capacity, excluding mobile rented diesel units. YEC projected that load and capacity shortfall would continue to increase during that time period. YEC attributed the increase in load to the new

[5] BESS Terms of Reference, PDF pg. 2

industrial mine loads at the Minto, Alexco, and Victoria Gold mines[6] and to electrification policy initiatives, such as the Government of Canada's zero-emission vehicles sales target of 10% by 2025, 30% by 2030, and 100% by 2040.[7]

YEC's current method of mitigating the capacity shortfall is relying on rented diesel units. However, in YEC's view, these units introduce risks since there are uncertainties around their continued availability, their acceptable performance, and YEC's ability to spatially accommodate the units. YEC stated that these risks potentially expose grid customers to unreliable generation capacity.[8] For these reasons, YEC submitted that maintaining the status quo was not a feasible option in the circumstances and that permanent solutions were needed.

YEC indicated that, as provided for in its 2016 Resource Plan and 10-Year Renewable Electricity Plan, it continues to pursue new renewable energy development to reduce its reliance on thermal generation. Part of this renewable strategy is to develop the BESS Project.[9] YEC stated that the primary need for the BESS Project is to help meet its dependable capacity requirements under the N-1 criterion for the YIS. YEC defined "dependable capacity" as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months based on the inflows of the five driest inflow years in history.[10]

YEC anticipated that the BESS Project would provide 7.2 MW of dependable capacity in the near term, displacing the requirement to rent four diesel units rated at 1.8 MW. YEC considered other alternatives and indicated that these alternatives did not provide dependable capacity in the near term. For example, one of the options included the Whitehorse Hydro #4 (WH4) Uprate Project, which would increase the maximum water flow and provide 0.9 GWh of annual additional energy. However, due to the downstream Yukon River system ice flow restrictions, the WH4 Uprate Project would not provide additional dependable capacity.

YEC advised that the BESS Project would be required to close the gap in the capacity shortfall, even if the other major projects in the 10-Year Renewable Electricity Plan proceeded; namely, the Atlin Hydro Expansion and the Moon Lake Pumped Storage projects. YEC submitted that, after connecting the Atlin Hydro Expansion project, there would still be around 8.9 MW of capacity shortfall.[11] YEC indicated that if the Moon Lake Pumped Storage project connected and there was no BESS Project, there would be a slight capacity surplus in 2028-29, but then a capacity shortfall would exist in the following years.[12]

[6] YEC Application, Section 4.1.2, PDF page 29.
[7] YEC responses to YUB IRs, YUB-YEC-1-1, PDF page 7.
[8] YEC Application, Section 4.2, PDF page 33.
[9] YEC Application, Section 4.1.2, PDF page 29.
[10] YEC responses to YUB IRs, YUB-YEC-1-17, PDF page 46.
[11] YEC Application, Section 4.1.2, PDF page 32, Table 4-1.
[12] Transcript Volume 2, PDF page 8, lines 17 to 25, and PDF page 9, lines 1 to 9.

YEC indicated that the BESS Project would reduce ratepayer costs compared to rented diesels or any other option, citing the following unique features as contributing to ratepayer savings:

- A $16.5 million federal grant, which reduces the estimated capital cost (2020$) to $15.2 million;
- Displacement of diesel rental costs (or similar fixed capital and non-fuel O&M [operations and maintenance] costs for any other thermal option considered);
- Operating reserve use savings from the battery, displacing thermal generation driven by the current requirements to use hydro for operating reserve [footnote removed]; and
- Fuel cost savings from battery use for diesel peak shifting.[13]

YEC stated that net ratepayer savings would occur each year with the BESS Project and that there would be $12.7 million net present value ratepayer savings over the 20-year project life. The estimate of annual ratepayer impacts was provided in Table 4-3 in YEC's Application[14] and excluded additional thermal fuel cost-saving benefits from improved hydro unit efficiency, nonfuel thermal O&M cost savings, or updated thermal fuel prices.[15] In response to one of John Maissan's IRs, YEC provided updated versions of Table 4-3 based on the following conditions: March 2021 LNG and diesel fuel prices, the project coming in at 30% below the estimate, the project coming in at 30% above the estimate, and long-term avoided costs of diesel and LNG at $0.277 per kWh and $0.248 per kWh, respectively.[16] YEC stated that ratepayer benefits were demonstrated in each of the updated tables.[17]

Regarding the reliability benefits of implementing the BESS Project, YEC noted that the project would reduce the impact of outages on customers, improve overall reliability of service, and enhance the capability of the system to integrate new Independent Power Producer (IPP) renewable generation.[18] The BESS Project would primarily be used to contribute to the N-1 capacity reserve required to meet YEC's non-industrial peak load under the single largest contingency, which would be the loss of the Aishihik generating facility or the transmission line connecting the facility to the YIS.[19] The BESS Project would also provide operating reserve

[13] YEC Final Submission, PDF pages 6 and 7.
[14] YEC Application, Section 4.3.2, PDF page 43, Table 4-3.
[15] YEC Final Argument, PDF page 8.
[16] YEC responses to John Maissan's IRs, JM-YEC-1-33, PDF pages 43 to 46.
[17] YEC Final Argument, PDF page 8.
[18] YEC Final Argument, PDF page 8.
[19] YEC responses to YUB IRs, YUB-YEC-1-36, PDF page 138.

when excess water is available, allowing hydro generating units to operate more efficiently and meet system load and reduce the reliance on thermal generation.[20]

YEC stated that using the BESS Project could save up to 1,837 MWh of diesel and 17,043 MWh of LNG, or $3.374 million, based on 2021 fuel prices.[21] According to YEC, this estimate was conservative because it assumed one-third of the Hatch Engineering Utility Battery Feasibility Study Final Report (Hatch report)[22] estimated thermal fuel generation, did not include any nonfuel O&M cost savings or benefits for improved hydro unit efficiency, and used lower fuel prices from mid-2020.[23]

YEC identified that the BESS Project provided other reliability benefits, including diesel peak shifting, rapid black start and outage restoration, grid reliability and ancillary services (including frequency regulation, coverage of large generation unit outages, prevention of load shedding events and renewable integration), load loss stabilization, and reactive power support.[24] While YEC estimated a small net economic benefit of approximately $10,600 per year (estimated in 2022$) for diesel peak shifting, it could not quantify the economic benefits for the other reliability benefits.[25]

Yukon Conservation Society

YCS was in favour of the BESS Project, indicating that one of the primary benefits was the project's ability to integrate renewable generation onto the YIS. YCS agreed with the technical and ratepayer benefits provided by YEC in the Application. YCS indicated that the forecast in ratepayer savings in response JM-YEC-1-33(a)[26] was conservative, as it did not include volatility of future diesel fuel prices and application of a future carbon tax. If a federal carbon tax was implemented, YCS submitted that ratepayers would realize even further savings with the BESS Project.[27] YCS also noted that the project would allow the YIS to become more resilient to climate change and add "robustness" to the system in cold winters when there is a higher risk of ice build-up downstream of a hydro generating facility.[28]

John Maissan

John Maissan agreed that there was a public need for the BESS Project, indicating that the reliability of service would increase and that all customers would experience rate benefits.

[20] YEC Application, Section 3.1.2.2, PDF pages 14 and 15.
[21] YEC Application, Section 4.2.3, PDF page 42.
[22] YEC Application, Appendix B: Hatch Engineering Utility Battery Feasibility Study Final Report – Phase 1, PDF pages 55 to 178.
[23] YEC Final Argument, PDF page 12.
[24] YEC Opening Statement, PDF page 5.
[25] YEC Application, Section 4.2.3, PDF page 42.
[26] YEC responses to John Maissan's IRs, JM-YEC-1-33(a), Table 1, PDF page 43.
[27] YCS Final Argument, PDF page 6.
[28] YCS Final Argument, PDF page 5.

Mr. Maissan stated that peak non-industrial load has been growing in recent years, mentioning the three grid-connected mines and increase in new residential housing. In Mr. Maissan's view, while YEC is increasing its renewable energy supply options, the YIS will not be able to meet the N-1 planning criterion without rented diesel generating units, until the Moon Lake Pumped Storage project connects a decade from now.[29]

Mr. Maissan stated that, to provide a unit of dependable capacity, a generating unit did not need to be running at capacity continuously and was only required to lower the peak load.[30] The peak load occurs over a short period of time, and smaller amounts of dependable capacity are required for the remainder of the day. The BESS Project could reduce the load by 7.2 MW during the peak load hours and then be recharged during the nighttime. Mr. Maissan added that YEC had been conservative in estimating the net present value of the project.[31]

Mr. Maissan agreed with YEC's assertions that the BESS Project could assist in operating reserve support, diesel and LNG peak shifting, grid reliability, load loss stabilization, black start and outage restoration, and ancillary services and reactive power support.

Utilities Consumers' Group

UCG had concerns with the certainty around system load levels presented by YEC in the Application. It stated that YEC acknowledged uncertainty around the changing plans of industrial customers. As a result, UCG concluded that YEC continued to make an error of applying sales growth rates experienced over past time periods to derive weather-normalized use per customer forecast.[32] UCG questioned why YEC was not pursuing installation of on-site generation with guaranteed upfront payment for interim mining loads, as on-site generation with guaranteed upfront payment by these industrial loads would protect the interests of other Yukon ratepayers.[33]

Finally, UCG submitted that YEC's board of directors' instruction to focus on renewable projects prevented YEC from completing a fulsome review of potential alternatives in closing the capacity shortfall gap, e.g., pursuing a large new permanent diesel plant instead of the BESS Project.

Board Views

The Board provides its report and recommendations about Section 3.a. of the Terms of Reference in the following three subsections:

(i) the public need for the BESS Project under various reasonable electric load forecasts, including near-term requirements related to industrial and non-industrial loads;

[29] John Maissan Final Argument, PDF page 2.
[30] John Maissan Final Argument, PDF page 3.
[31] John Maissan Final Argument, PDF page 8.
[32] UCG Final Argument, PDF page 8.
[33] UCG Final Argument, PDF page 8.

(ii) the effect of the BESS Project on the rates of customers; and

(iii) the reliability of electricity service provided to customers.

Public Need for the Bess Project

The Board finds that a need for the BESS Project in the near term has been established. The Board agrees with YEC's and Mr. Maissan's submissions that new load growth is anticipated due to: new industrial mine loads at the Minto, Alexco and Victoria Gold mines; an increase in residential housing in Yukon and an associated increase in demand for electric heat; and government electrification policy initiatives resulting in, for example, a projected increase in zero-emission vehicles.

In the circumstances detailed by YEC in its Application, supporting documents, and testimony, the Board finds sufficient evidence on the record to reasonably accept that load will continue to grow and that a large capacity shortfall gap will exist until YEC connects additional supply options. One of these options is the BESS Project, and removing it from the supply mix would keep the system at a capacity shortfall.

Currently and into the future, unless a permanent thermal option is pursued, YEC will need to continue relying on rented diesel units to address the capacity shortfall. The BESS Project is expected to operate in lieu of, and eliminate the need to rent, four 1.8 MW diesel units. In its Application, YEC mentioned the challenges of finding these rental units and locating and connecting these units safely to the YIS.[34] YEC provided the Board with its competitive process for sourcing rented diesel units in 2018-19, 2019-20, and 2020-21. During the years 2018-19, 2019-20, and 2020-21, YEC ran a one-year public competitive tender process for six 2-MW units for placement at the Whitehorse Rapids Generation Station, a three-year tender process for up to eight 2-MW units, and is searching the market for cost-effective options for rental units, respectively.[35] YEC also confirmed at the hearing that rented diesel units are not as reliable as more permanent solutions.[36] The Board is persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap.

YEC indicated that one alternative to meeting the capacity shortfall would be to connect a permanent thermal (diesel) plant. However, YEC stated that this option held less popularity with stakeholders in public consultation and was rejected by its board of directors.[37] While the BESS Project drew some stakeholder concerns, YEC indicated that the concerns were fairly manageable.[38] From that perspective, the Board considers that the BESS Project appears more favorable to stakeholders than a permanent diesel plant at this time.

[34] YEC Application, Section 4.2, footnote 40, PDF page 33.
[35] YEC responses to YUB IRs, YUB-YEC-1-17, PDF pages 46 and 47.
[36] Transcript Volume 1, PDF page 123, lines 21 to 23.
[37] YEC responses to YUB IRs, YUB-YEC-1-43, PDF page 159.
[38] Transcript Volume 1, PDF page 170, lines 10 to 14.

The effect of the project on the rates of customers

While the Board finds that there is a public need for the BESS Project, the ratepayer savings proposed by YEC are less persuasive to the Board. This is because the BESS Project is finishing the planning phase and moving to the procurement process stage, meaning that project costs are not firm.

While the Board agrees that the information provided on the record suggests ratepayer benefits, a significant part of the capital costs is associated with the battery, for which YEC is currently in the first stage of the procurement process.[39] In response to an information request from Mr. Maissan, YEC submitted that, over its predicted life, the BESS Project would break even in terms of no longer providing ratepayer savings if the capital costs increased by 42.5%.[40]

At the hearing, YEC mentioned that, over the next few months, it would receive details from the request-for-proposal (RFP) process for the battery, which would then confirm a substantial portion of the capital cost. YEC would then go to its board of directors to make a final investment decision.[41] As stated, the Board had no information on the selected vendors and the costs associated with these vendors because YEC has not finished the RFP and selection processes.

In addition, the Board is unsure whether the projected cost savings will remain for the 20-year project lifespan or if the BESS Project will last for 20 years. The long-term costs will likely be impacted by the vendor selected, obligations of the vendor, and any agreements with the First Nations for land lease and investment, as well as costs for mitigations required from YESAB, Nav Canada, and Transport Canada permits and any other currently unknown costs associated with outstanding permits, purchases, negotiations, and other agreements. It is for these reasons that the Board cannot fully accept the estimated economic benefits of the BESS Project provided by YEC for operating reserve support and diesel peak shifting, both in the short and long term.

Given the early stage of the project and the significant +/- range to the engineering estimates, the Board finds that there are too many uncertainties for it to make a recommendation on the effect of the BESS Project on the final rates of customers. As noted throughout this report, the final costs to be included in rates will be subject to a prudency review in YEC's future GRA.

Reliability of electricity service

With regard to reliability, the Board agrees that the BESS Project could provide operating reserve support and increase grid reliability. While YEC brings up additional reliability benefits for the BESS Project, the Board notes that these benefits are not significantly required to meet a

[39] YEC responses to YUB IRs, YUB-YEC-1-13, PDF page 37.
[40] YEC responses to John Maissan's IRs, JM-YEC-1-33, PDF page 43.
[41] Transcript Volume 2, PDF page 20, lines 13 to 19.

need at this time. The Board elaborates on its views around reliability in Section 3(b) of this report.

4.2 Capability of Existing and Expected Assets to Meet Forecast Load Requirements — Term of Reference 3.b.

The Minister's Terms of Reference requested the Board to report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> 3.b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities to provide reliable electric power generation to meet the forecast load requirements and criteria and the effect of the BESS Project on this capability.

Yukon Energy Corporation

YEC stated that 84% of its 2021 forecast generation would be supplied by hydroelectric generation, with almost all of the balance supplied by diesel and LNG thermal generation.[42] Since Yukon's system is an isolated grid, YEC must supply its own capacity and energy, which includes securing reserve capacity in order to meet load during the winter peak periods. As mentioned in Section 3(a) of this report, YEC's generation capacity planning criterion is based on the single contingency dependable capacity criterion, which requires the YIS to have enough dependable capacity to supply the forecast non-industrial peak winter demand under the largest single contingency.

YEC stated that planning is based on non-industrial load since all major industrial customers maintain sufficient on-site generation for their own emergency purposes. YEC submitted that all of the renewable and thermal supply options identified in the Application are required to remove reliance on rented diesel units in order to address the existing and ongoing forecast capacity shortfall.[43] Added to this, YEC represented that the BESS Project would provide support in meeting the dependable capacity criterion. More specifically, the BESS Project would provide 7.2 MW of dependable capacity in the near term, displacing the requirement to rent four diesel units rated at 1.8 MW.

YEC explored a variety of energy storage technologies, including storage through pumped hydro, compressed air, flywheel, flow battery, lead acid battery and supercapacitors, and found that the lithium ion battery technology was best suited for meeting its generation capacity planning criterion. YEC planned to develop the project using construction technologies that it states are suited for northern climate conditions and using similar technology employed for battery projects installed in Northern Quebec, the Northwest Territories, and Alaska.[44]

[42] YEC Application, Section 4.1.2, PDF page 28.
[43] YEC Final Argument, PDF page 10.
[44] YEC Opening Statement, PDF page 6.

YEC indicated that the BESS would be designed to meet the following standards:

- UL 1642 Standard for Lithium Batteries
- UL 1973 Standard for Batteries for Use in Light Electric 1 Rail (LER) Applications and Stationary Applications
- UL 9540 Standard for Energy Storage Systems and Equipment
- NFPA 855 Standard for the Installation of Stationary Energy Storage Systems
- IEEE 1547 Standard for Interconnecting Distributed Resourced with Electric Power Systems
- UL 1741 Inverters Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources[45]

YEC added that it would take a number of proactive steps to ensure that fire and other safety risks were managed effectively. YEC indicated that fire suppression would be a key component of the battery system design and selection and that the design would use several automated mechanisms to prevent fires from starting. More specifically, YEC would install a fire suppression system and alarms in each battery container, check and maintain the fire suppression system routinely, use fire-retardant module containers to isolate a single pack of battery cells if a fire occurs, use containers with pressure relief valves that allow gas to escape and prevent a container explosion, space the containers apart to prevent a fire from spreading, develop a comprehensive fire and emergency response plan, and commit to providing the required training to local firefighters and emergency response staff.[46]

YEC advised that an essential requirement for reliable operation of the Yukon system is ensuring that there is enough operating reserve support to accommodate for variations in load. Currently, the operating reserve criteria are achieved by operating a hydro generating unit below its maximum capacity. Thermal generation is used to meet load that exceeds the available hydro generation. YEC indicated that if the BESS Project is used for operating reserve support, there would be a direct reduction in thermal generation and improved efficiency of hydro generating units by operating them at their most efficient output more frequently.[47] For example, if a modest efficiency gain of 0.5 to 1% was realized for the hydro generating units, 2.2 to 4.4 GWh of additional energy would be provided by the hydro generating units.[48]

YEC submitted that utilizing the BESS Project as an operating reserve was compatible with using the project in meeting the N-1 dependable capacity criterion. The first reason given was that both required the BESS to retain storage in different time periods. More specifically, the N-1

[45] YEC responses to YUB IRs, YUB-YEC-1-56, PDF pages 315 and 316.
[46] YEC responses to YUB IRs, YUB-YEC-1-46, PDF pages 168 and 169.
[47] YEC Final Argument, PDF page 12.
[48] YEC Application, Section 3.1.2.2, PDF page 16.

dependable capacity would be for events during the coldest period of winter, a time when using the BESS for operating reserve support provides minimal benefit in reducing net thermal generation.[49] The second reason given was that both use cases (meaning the N-1 use case and the operating reserve use case) would have minimal impact on battery life, with an estimate of one 30-minute operating reserve event per month and one two-week N-1 event every 10 years.[50]

In addition to providing support in meeting the N-1 dependable capacity criterion and operating reserve requirements, YEC indicated that the BESS Project would provide other reliability benefits, which included diesel peak shifting, rapid black start and outage restoration, grid reliability and ancillary services, load loss stabilization, and reactive power support.

YEC advised that the BESS Project could be discharged in lieu of diesel generation during peak hours and recharged overnight with LNG or hydro generation, thereby reducing thermal fuel costs and greenhouse gas emissions.[51] YEC indicated that the BESS had the potential to shift between 108 to 244 MWh per year of diesel generation between Whitehorse and Faro diesel. However, YEC noted that if the BESS Project was providing operating reserve during periods of peak diesel generation, a priority must be set for BESS operation,[52] since operating reserve support could not be provided at the same time as diesel peak shifting.

YEC described its current process for black start and outage restoration in its Application and submitted that the BESS Project could improve this process. When YEC is required to perform black start operation, it sectionalizes the YIS into smaller load segments that are re-energized sequentially using smaller individual generators. Because the system is segmented into numerous load blocks, and because some of the switching is of a manual nature, the process can take up to two hours depending on the extent and severity of the outage.[53] YEC submitted that the black start and outage restoration process would improve if the BESS was used for grid re-energization. The BESS Project would enable significantly larger load segments (more specifically, 20 MW) to be restored at once, meaning the project would enable rapid pickup of the grid.[54] However, YEC noted that this process accounted for more than half of the estimated BESS annual throughput, meaning the BESS Project would incur operating efficiency losses of 15% on the throughput.[55] YEC indicated that the overall savings from enhanced system restoration would offset any efficiency loss costs.

Regarding grid reliability and ancillary services, YEC stated the BESS Project could respond to large frequency excursions, cover the loss of large generating units, prevent load shedding events, and improve power quality and customer reliability.[56] More specifically, YEC advised

[49] YEC Final Argument, PDF page 12, footnote 17.
[50] YEC Final Argument, PDF page 12, footnote 18.
[51] YEC Application, Section 3.1.2.2, PDF page 18.
[52] YEC Application, Section 3.1.2.2, PDF page 18.
[53] YEC Application, Section 3.1.2.2, PDF page 17.
[54] YEC Application, Section 3.1.2.2, PDF page 17.
[55] YEC Application, Section 3.1.2.2, PDF pages 17 and 18.
[56] YEC Application, Section 3.1.2.2, PDF pages 18 and 19.

that the BESS could discharge prior to load shedding events or charge in the event of a significant load loss, both at a partial discharge or charge cycle.[57] YEC also highlighted that the BESS inverters could provide real and reactive power simultaneously to the YIS, since providing reactive power support did not deplete the energy stored in the BESS. However, significant reactive power compensation was not typically required on the YIS.[58]

Yukon Conservation Society

The views of YCS regarding this aspect of the project are similar to the views summarized in Section 3(a) of this report.

John Maissan

Mr. Maissan agreed that the BESS Project improved the capability of the Yukon system by providing reliable electricity service. More specifically, the BESS Project would support meeting the N-1 dependable capacity criterion, provide operating reserve support which would improve hydro generating unit efficiency and decrease reliance on thermal generation, improve grid reliability, improve the black start and outage restoration process, and provide ancillary service and reactive power support.[59] In Mr. Maissan's view, utilizing the BESS Project for operating reserve would allow for more efficient utilization of hydro generation and could reduce the amount of thermal generation required whenever load surpassed the reduced output of the hydro generating units.[60] Due to its instantaneous nature, the BESS Project could improve grid reliability by starting and supplying load a tripped generating unit was carrying within 150 to 200 milliseconds.[61] Mr. Maissan also supported the fact that the BESS Project could act as load and charge in circumstances where there is more generation on the YIS.

Utilities Consumers' Group

UCG was less inclined to support the BESS Project's effect on the system's capability of providing reliable electrical service. In its final submission, UCG stated that it was not clear whether the forecasts used to justify the need for the BESS Project were significantly influenced by climate change impacts. It submitted that the forecasting models were proven to be very costly for Yukon ratepayers and that there continued to be a lack of evidence that showed the models provided accurate forecasts.[62] UCG mentioned the YECSIM model[63] and stated that

[57] YEC responses to YUB IRs, YUB-YEC-1-61, PDF page 362.
[58] YEC Application, Section 3.1.2.2, PDF page 14.
[59] John Maissan Final Argument, PDF page 6.
[60] John Maissan Final Argument, PDF page 4.
[61] John Maissan Final Argument, PDF page 4.
[62] UCG Final Argument, PDF page 10.
[63] UCG explained that the YECSIM model is a power benefits simulation model developed in 2007 by KGS Ground Consulting Engineers and that it is used by YEC to forecast its long-term average hydro generation for different load scenarios. UCG indicated that the YECSIM model is custom-made to consider all significant factors affecting the operation of YEC's system, including complex rules of operation and regulatory demands on YEC. See UCG's Final Argument, PDF page 10.

there was a lack of comparing actual with forecasts made with using the model to verify accuracy.[64]

Board Views

The BESS project supports YEC in its capability of providing reliable electric power supply to meet the forecast load requirements in future years. From the information that has been presented on this record, the Board is satisfied that the project will not hinder existing and currently committed (and expected) generation and transmission facilities.

For example, the Board asked YEC questions regarding the transmission requirements for the BESS Project.[65] YEC responded that the BESS Project would be connected under the Whitehorse Interconnection Project, which was currently in preliminary stages. YEC advised that the Whitehorse Interconnection Project would be required regardless of whether the BESS Project proceeded. Accordingly, the BESS Project fits within YEC's already existing plans for upgrading the YIS.

At this stage of project development, YEC is considering requests-for-proposals from vendors for the following lithium ion battery chemistries: nickel manganese cobalt lithium (NMC), nickel cobalt aluminum lithium (NCA), and lithium iron phosphate (LFP). While there are some variations in battery chemistries,[66] based on the information before it, the Board finds sufficient evidence to suggest that any of the battery chemistries are likely suitable for the BESS Project. However, the Board expects YEC to follow all applicable design standards and take all of the steps necessary to ensure that fire and other safety risks are managed effectively, as was outlined in the Application.

The BESS Project provides N-1 capacity support in the winter season. By definition, this is idle capacity waiting for a catastrophic event (the N-1 event) to activate and operate. Currently, the rented diesel units meet this requirement, and the BESS would likely displace the future need for four additional rented diesel units. An economic and system benefit of the BESS is that it also supports the operating reserve requirements of YEC and, in doing so, could allow for gains in efficiency for hydro generating units. Currently, a hydro generating unit must operate at less than its full capability in order to provide operating reserve to ramp up to address a loss in generation.[67] This means that there is more likelihood of load exceeding the available hydro generation, which will then require thermal generation to provide additional energy to meet the system load.[68] Using the BESS Project as an operating reserve allows hydro generating units to run at a higher output and reduces reliance on thermal generation. While YEC could not quantify the efficiencies gained by the hydro generating units connected to the YIS,[69] the Board agrees at

[64] UCG Final Argument, PDF page 10.
[65] YEC responses to YUB IRs, YUB-YEC-1-3, PDF pages 11 to 14.
[66] Transcript Volume 1, PDF page 161, lines 19 to 25, and PDF page 162, lines 1 and 14 to 17.
[67] YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 55.
[68] YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 55.
[69] YEC responses to YUB IRs, YUB-YEC-1-20, PDF page 54.

a conceptual level that the units will be used more efficiently since they will not be saving generation for operating reserve.

The Board also observes that YEC may choose on a given day in the winter not to use the BESS Project for other services, such as diesel peak shifting or responding to frequency events.[70] The Board interprets this to imply that the secondary reliability benefits of the BESS Project cannot be realized at all times. While the Board does not currently consider this to be a major concern, the number of times the BESS is used for secondary reliability benefits might increase as more renewable supply options connect to the YIS. For example, YEC stated that frequency excursion events are likely to increase as more intermittent renewables are added to the grid,[71] which would increase the use of the BESS for the secondary benefits. The Board foresees that there could be conflict between the secondary benefits of the BESS Project as more intermittent renewables are added to the grid and the addition of the BESS to assist YEC with meeting the N-1 dependable capacity criterion and providing operating reserve support in the future.

YEC's proposal to meet these reliability requirements with the BESS is more favorable compared to the alternative of using rented diesel units, as it would automatically maintain system frequency and assist with automatic voltage control on the grid. In contrast, the purpose of rented diesel units was primarily for peaking generation and N-1, and was not intended to deal with YEC's system as a whole.[72] Additionally, the BESS Project would increase the size of load segments that could be picked up during the black start process, thereby reducing the time required for grid restoration. More specifically, YEC stated that 20 MW of load could be brought up immediately.[73] YEC also noted that the BESS Project could be started instantaneously, whereas rented diesel units take approximately five minutes to start.[74] However, utilizing the BESS Project for black start and outage restoration would account for more than half of the estimated BESS throughput, resulting in operating efficiency losses.

The Board is unable to provide a recommendation as to whether overall savings from enhanced system restoration will offset any efficiency loss costs at this time because the BESS Project is in its preliminary stages. It is likely that the BESS Project will have to be operational before data will be available to inform the savings and the costs.

[70] YEC responses to YUB IRs, YUB-YEC-1-67, PDF page 371.
[71] YEC Application, Section 3.1.2.2, PDF page 19.
[72] Transcript Volume 1, PDF page 176, lines 18 to 20, and PDF page 178, lines 22 to 24.
[73] Transcript Volume 1, PDF page 180, lines 4 to 7.
[74] Transcript Volume 1, PDF page 180, lines 18 to 20.

4.3 Risks for the BESS Project and Impacts on Rates for Customers — Term of Reference 3.c.

The Minister's Terms of Reference request that the Board make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.[75]

YEC identified project risks in Section 4.3 of the Application. Project risks are categorized into two groups, as follows:

1. Group 1 – Project technical risks, design risks, and capital cost risks.
2. Group 2 – Risks related to timing delays from the Board, *Yukon Environmental and Socio-economic Assessment Act* (YESAA), NavCanada, and Transport Canada regulatory or permitting processes.

In YEC's view, the Group 1 risks were manageable through selection of an experienced vendor, use of an owner's (YEC or its designate) engineer with experience procuring battery vendors, and the ability to select the specific project solution based on both technical compliance and price and taking into consideration Whitehorse climate conditions.

Ratepayer impacts for Group 1 were tied to ultimate capital costs for the project, project performance and timing that affect the expected BESS benefits of reduced thermal generation, and improved reliability.

Group 2 risks related to the timelines that would delay the project from proceeding in mid-2021, resulting in an extended need and related costs for diesel rentals past the winter of 2022/23.

For Group 2, YEC stated that impact to ratepayers would relate to delays in the project proceeding and the added costs related to such delays.[76]

Yukon Conservation Society

YCS stated that the project has benefits from a technical standpoint and the benefit to ratepayers is a positive when compared to renting diesel generators. YCS added that the forecast benefit to ratepayers is conservative because it does not include volatility in diesel fuel prices in the future nor the potential of a carbon tax being applied to northern jurisdiction electricity providers.[77]

John Maissan

From a technical perspective, Mr. Maissan noted that BESS systems were being utilized globally using technologies similar to that proposed by YEC. He provided several examples of BESS projects in Canada. He added that the heating, ventilating, and air conditioning (HVAC) or

[75] Minister of Justice's Terms of Reference, PDF page 3.
[76] YEC Application, PDF pages 43 and 44.
[77] YCS Final Argument, PDF page 6.

temperature management systems required to meet local ambient conditions exist in Whitehorse and should not pose any problems for the BESS Project. Mr. Maissan's view was that the technical risk was low.[78]

For reliability, Mr. Maissan stated that all the planned functions of the BESS have positive results on either the YIS costs or on power reliability and quality.[79] Mr. Maissan noted that the Application demonstrated a financial benefit, with a net present value of $12.676 million. It was his view that this estimate was conservative and that the following benefits should also be considered:

- Avoided diesel rental costs
- Annual savings from operating reserve
- Annual savings from peak shifting
- Financial savings due to updated fuel prices
- Variable operating cost savings are not presently included in thermal generation savings
- Modest efficiency gains of 0.5 to 1% in the hydro generator operation with the BESS providing the operating reserve
- Reduced diesel generation due to a reduction in grid outages and faster restoration from outages
- Consumer benefits and cost savings due to fewer unscheduled outages
- Savings from avoided potential carbon taxes[80]

Mr. Maissan provided the following summary points to support his opinion that:

1. Operating reserve benefit is conservatively underestimated.
2. Diesel and liquefied natural gas (LNG) peak shifting benefit is very likely underestimated.
3. Present fuel costs are not included, net present value (NPV) increases by $1.85 million.
4. Variable operating cost savings are not included, and there is a $94,000 annual benefit for operating reserve only.
5. Hydro operating efficiency gain is not included, and there is an NPV of over $2 million.

[78] John Maissan Final Argument, PDF pages 6 and 7.
[79] John Maissan Final Argument, PDF page 7.
[80] John Maissan Final Argument, PDF page 9.

6. Reduction in Yukon Energy's [YEC's] or customers' costs of outages, not considered.

7. Taxpayer subsidy for carbon tax savings, not considered.[81]

Utilities Consumers' Group

Despite the direction from the government in the Terms of Reference, UCG commented that it was surprised that YEC witnesses at the hearing were not prepared to talk about the ultimate impact on ratepayers.[82] UCG also expressed concerns regarding ineligible costs and the "transfer payment agreement".[83] Further, UCG stated that project costs have significantly increased since the project was first reviewed by the Board in 2018, that costs have changed since the project cost was evaluated by the federal government, and that the current cost range to ratepayers is between $15.2 million and $24.71 million.[84]

The project was not supported by UCG. UCG pointed to the response to JM-YEC-1-33(d) to inform its position that the project puts ratepayers at risk and will likely exceed current cost estimates. In that response, where YEC used a high estimate for project costs, negative benefits were identified for the initial seven years of the project (nearly half the project life).[85]

UCG noted that there was no formal agreement between AEY and YEC for the proposed route, creating the possibility of further unidentified costs for the project.[86]

UCG cited concerns regarding the 25-year site lease, and it noted the option for a further 25-year renewal. It identified additional concerns about the cost impact of such a lease on ratepayers.[87]

UCG submitted that there is no evidence on the record of this proceeding that quantifies or justifies adding the BESS to the YIS or that the BESS Project will result in the hydro generation units being operated more efficiently. YEC confirmed during the hearing that they will have to pay City of Whitehorse taxes on any development on the Kwanlin Dün site and that municipal taxes are on the rise. UCG stated that the property tax impacts of this proposed project over its productive life are another unknown risk that ratepayers are being asked to absorb.[88]

Finally, UCG stated that a 20% overbuild of the BESS Project is a cost component that has not been adequately justified given the uncertainty related to pending proposals from vendors.[89]

[81] John Maissan Final Argument, PDF page 10.
[82] UCG Final Argument, PDF pages 10 and 11, paragraph 56.
[83] UCG Final Argument, PDF page 11, paragraph 57.
[84] UCG Final Argument, PDF page 11, paragraphs 59 and 60.
[85] UCG Final Argument, PDF pages 11 and 12, paragraphs 61 to 64.
[86] UCG Final Argument, PDF page 12, paragraph 66.
[87] UCG Final Argument, PDF page 12, paragraph 67.
[88] UCG Final Argument, PDF pages 12 and 13, paragraphs 69 to 73.
[89] UCG Final Argument, PDF page 13, paragraph 74.

Yukon Energy Corporation

YEC qualified its assessment of risks by stating that the assessment must be based on existing information and estimates, taking into account that final decisions on the BESS Project are still to be made.[90]

The following risk categories were discussed by YEC:

- Technical
- Regulatory
- Capital cost

Technical risks

As discussed in Section 3.2, the first technical risk discussed was operating experience in northern climates. To address this risk, YEC cited similar technology being used in northern Quebec, the Northwest Territories and Alaska. It stated that the size of the system does not impact the ability to operate in the Arctic. By using a self-contained system suited for northern climate conditions and appropriate HVAC systems, implementation issues are reduced.[91] YEC also noted that no issues were raised regarding the lithium ion technology. YEC did add that it will "work with vendors to assess options for ensuring end-of-life capacity".[92]

Regulatory risks[93]

From a regulatory perspective, YEC stated that it does not anticipate material design modifications resulting from the regulatory approvals and review process, no special added costs are expected in order to comply with approvals and permits required, and the key terms for the lease agreement with KDFN have been resolved.

YEC stated that the project followed a public engagement process and public concerns were taken into consideration. The YESAA project proposal was filed with the Whitehorse Designated Office on April 29, 2021. NavCanada and Transport Canada assessment processes review timelines and permitting requirements are well understood and any cost impacts related to required mitigation are expected to be minimal.

Capital cost risks[94]

As stated earlier, YEC's preliminary estimated total capital cost of $31.7 million (2020$, +/-30% accuracy) for the BESS Project includes $16.5 million in funding from the federal government's ICIP, leaving a net capital cost to YEC of $15.2 million to be recovered from ratepayers.

[90] YEC Final Argument, PDF page 14
[91] YEC Final Argument, PDF pages 14 and 15.
[92] YEC Final Argument, PDF page 15.
[93] Taken from YEC Final Argument, PDF page 16.
[94] This section is summarized from YEC's Final Argument, PDF pages 17 to 19.

YEC added that the capital cost estimates provided in the Hatch report were class 4[95] cost estimates, which include a 15% contingency on non-owner costs such as planning. The benchmarks used by Hatch were based on public information or Hatch's in-house data developed through other projects involving Hatch. The Hatch cost estimates were derived based on benchmark pricing of batteries of similar projects, with allocations for project-specific considerations like cold weather, transportation, allocation for installation, and allocation for other electrical and communication components within the BESS. Other capital expenditures were based on engineering costs as well as site preparation costs, which were derived based on estimates from Hatch's civil engineering team.[96]

YEC reiterated that the project would still break even with a 42.5% increase in capital costs, assuming the most recent actual fuel prices. YEC submitted that the BESS Project's capital cost risks will be largely resolved prior to the final stage-gate decision by YEC's board of directors expected in August 2021. YEC submitted that the evidence confirms that the BESS Project has a low level of capital cost risk once that stage is reached.

Board Views

The Board will review the risks associated and impacts to ratepayers regarding the BESS Project for each of the three risk categories identified by YEC.

Technical risks

YEC identified that the technical risk is operating a new technology in a northern climate. YEC submitted that this risk is not large and it cited several examples of BESS-type projects operating in northern climates. As discussed in Section 3.2, the Board notes that generally those projects are of a scale smaller than YEC's proposed BESS Project, they have been in service for three years or less, and they are not planned to be utilized in the manner YEC proposes for the BESS Project.

The Board accepts that BESS-type projects in self-contained units with proper HVAC systems should be able to operate as planned in Yukon. But there are risks; YEC noted certain risks in the hearing.

The YEC witness, Ms. Zuliani, stated that no lithium ion battery has exploded in the Arctic but noted there had been a few fires. She later added that those fires have been reviewed and strategies are ongoing to develop safety protocols, and those are included in Hatch's specifications. [97]

A few fires over a small population size is statistically significant.

[95] Class 4 is a level of engineering estimate with an accuracy of +/- 30%. By comparison, a class 5 engineering estimate has an accuracy of +/-50%. (See Transcript Volume 3, PDF page 16, line 19, to PDF page 17, line 3.
[96] Transcript Volume 2, PDF page 52, line 18, to PDF page 53, line 1.
[97] Transcript Volume 3, PDF page 40, line 21, to PDF page 41, line 19.

Although discussed in Section 3.2 of this report, given that there are a limited number of BESS-type projects in northern climates, it appears that there may be a real risk of a fire for a BESS-type project. Hatch has stated that it has developed safety protocols in its specifications, but without the provision of further evidence on the causes of those fires and specifically how Hatch's safety protocols address those causes, this is a risk that YEC, the Minister, the Yukon government, and ratepayers should be aware of.

Further, when questioned by Board counsel regarding thermal O&M costs, Ms. Zuliani stated that Hatch was relying on an experience of less than five projects.[98] Such limited experience introduces technical risk to, and operating costs for, this project.

Another technical concern is the life of the lithium ion batteries proposed for the project. YEC has carefully stated the project has an expected life of up to 20 years with either a modest overbuild at the beginning or an enhancement at the midpoint of the expected life. The Board considers that there is a risk if the life of the batteries fails to sustain for the expected 20 years, and that risk has not been proven abated as none of the battery installations in northern climates have existed beyond 8 years.[99] To mitigate this risk, the Board is of the view that YEC should ensure that there are sufficient safeguards from the vendor to ensure that key performance indicators for such items as battery life, battery failures, and warranties are accounted for in the vendor's obligations in supplying the batteries.

If any of the above technical risks occur, the impact to ratepayers will be higher rates and arguably less reliable service. Such risks, to the extent that they can be reduced by prudent management by YEC of external parties, for events such as battery fires and the service supplied by the battery vendors, will be essential to mitigating the technical risks.

Regulatory risks

YEC stated that it does not anticipate material design modifications resulting from the regulatory approvals and review process. At the hearing, YEC stated that the key terms for the lease agreement with KDFN had been resolved. The BESS Project will be located on land zoned for utility use within an existing environmental and socio-economic setting. The Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal was filed April 29, 2021. NavCanada and Transport Canada assessment processes are understood, and YEC expects that any cost impacts related to required mitigation would be minimal and within the current cost estimate.

YEC stated that the YESAA, NavCanada, and Transport Canada processes are underway. YEC stated that no further costs with respect to the various regulatory approvals are expected and any cost variances would likely be minimal. However, the regulatory processes are not complete, and

[98] See, e.g., the exchange from Transcript Volume 2, PDF page 60, line 20, to PDF page 62, line 23.
[99] See, e.g., the exchange from Transcript Volume 3, PDF page 40, line 21, to PDF page 42, line 6. YEC identified the oldest project from Alaska which started operation in 2015.

the Board does not have any reliable evidence by which to assess whether there would be any significant ratepayer impacts arising from costs associated with regulatory risks and approvals.

Capital cost risks

YEC provided the following testimony with respect to the estimate of its capital costs for the BESS Project:

> We talked at length this morning about the variability or uncertainty at this time in the capital costs. So the capital cost estimate is provided with a range of plus/minus 30 percent. But then maybe to jump ahead to probably what's the next question is, you know, we've also presented and discussed analyses which then evaluated the ratepayer benefits at the bookends of that risk range, and demonstrated that, even in that plus 30 percent capital cost scenario, there was still a net benefit to ratepayers. So that's one of the -- probably the principal financial risk at this time.[100]

As this is a class 4 estimate (+/- 30% accuracy), there is certainly a risk that the costs for the BESS Project may exceed the $31.7 million estimate. In the past 15 years, YEC has not completed a major capital project that was below the class 4 cost estimate with respect to a Part 3 application, except for when the scope of the project was reduced.[101]

Included in the capital costs are $3.7 million to provide a modest overbuild.[102] YEC has stated that the primary driver for this project is to provide capacity to meet the N-1 criterion in the near term. The N-1 criterion is a one-in-10-year event. Further, YEC has stated that this is a capacity issue and that the YIS does not have an energy shortfall. The theory for this added capacity is that it is there in case of a catastrophic N-1 event. If an event does not occur, then for purposes of the primary criteria, the asset is idle. It is used for backup or other short-term planning purposes.

Therefore, assets used primarily to provide capacity to meet the N-1 criterion are likely to be idle until the N-1 event occurs. YEC is proposing to include an additional 20% to its battery capacity to cover off future degradation of the battery. This seems redundant, as it appears the overbuild is a backup to the backup asset providing N-1 capacity.

YEC has not made a case that justifies spending $3.7 million to overbuild the BESS Project to provide or maintain capacity 10 years down the road. Such costs should be removed from the project unless YEC can provide economic justification for those costs to be included up front.

Nonetheless, as presented in the Application, the submissions of YEC and Mr. Maissan state that several savings opportunities have been either estimated conservatively or have not been included in YEC's financial analysis. The Board believes that some probability exists in regard to potential savings. The Board is satisfied that, with the 15% contingency included in the cost

[100] Transcript Volume 1, PDF page 124, line 21, to PDF page 125, line 7.
[101] See, e.g., the Carmacks-Stewart Transmission Project, Phase 1, where a substation included in the Part 3 application was subsequently removed from that phase of the project.
[102] YEC responses to YUB IRs, YUB-YEC-1-11(b), PDF page 32.

estimate, unknown items arising from other regulatory processes should be covered within the current estimate.

If YEC's testimony that the prices for containerized batteries are reducing is borne out, that will be shown in the results of the procurement process which will be competitively tendered. If YEC is able to achieve the savings as noted in the Application and elsewhere on the record of this proceeding, then the capital cost risks for this project can be managed by the utility using reasonable judgment.

However, given the margin of error in the class 4 estimates, any recommendations in this report are not a finding of prudency, and in a subsequent GRA when more accurate information is provided, the granting of an energy project certificate and an energy operation certificate will not deem the final project costs prudent. Further, if this project is approved by the Minister and there are changes to the scope of this project, YEC should notify the Minister and the Board about any scope changes that would result in cost increases beyond the 15% contingency or that would materially decrease the capital costs expected for the BESS project.

4.4 Alternatives to the BESS Project — Term of Reference 3.d.

The Minister's Terms of Reference require the Board to make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments.[103]

In its Application, YEC referred to its 10-Year Renewable Electricity Plan to address forecast energy and capacity shortfalls, noting that new resources will provide dependable capacity and will generally not displace what the BESS Project option can provide, i.e., the identified permanent resource capacity options are generally all needed to remove reliance on rented diesels and for addressing the forecast capacity shortfall. For example, the Moon Lake Pumped Storage project, when it is developed, is the only identified resource option aside from default new thermal fossil fuel generation, that has the capability to remove the forecast N-1 dependable capacity shortfall.[104]

YEC identified the following alternatives to the BESS Project:

- Standing Offer Program (SOP) and Micro-Generation Program: The SOP is included in the 10-Year Renewable Electricity Plan, which forecasts 40 GWh/year of energy delivered by the IPP sector by the year 2024. The Micro-Generation Policy envisions 6.5 GWh/year of delivered energy by the year 2024. However, no dependable capacity is available from SOP and micro-generation projects because they will be comprised of intermittent renewable resources, such as wind and solar.

[103] Minister of Justice's Terms of Reference, PDF page 3.
[104] YEC Application, PDF page 33.

- Whitehorse Hydro #2 (WH2) and Whitehorse Hydro #4 (WH4) Uprate Projects: These projects increase the efficiency and maximum capacity of the two Whitehorse generation units. However, the capacity increase for WH2 is less than 1 MW, and due to downstream Yukon River system ice flow restrictions, the WH4 does not provide additional dependable capacity.

- Potentially Available Near Term Enhanced Hydro Storage Projects: The Southern Lakes Enhanced Storage Project (SLESP) will expand the storage range on the Southern Lakes system, and the Mayo Lake Enhanced Storage Project (MLESP) seeks to enhance water storage at Mayo Lake. However, both hydro storage enhancement projects would not affect YIS requirements for new dependable capacity.

- Demand Side Management (DSM): DSM involves using incentives, electricity rate structures, and building and appliance codes and standards to encourage customers to reduce the amount of electricity they use. YEC's current focus of the DSM programs is on measures that deliver peak capacity savings (i.e., reductions in peak electricity consumption).

- Diesel Replacement: By replacing retired diesel generator units at existing generation facilities, YEC stated that it can reduce the need for added rental diesel generators. The total replacement diesel currently assumed is 12.5 MW. However, it noted that diesel replacement does not fully address the capacity shortfall.

- The Atlin (Pine Creek) Hydro Expansion Project: In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP and key principles and terms for an Agreement-in-Principle (AIP) for an electricity purchase agreement. Federal funding has been identified as a key requirement for this project to proceed. The objective is for this project to provide 8.5 MW of dependable capacity by 2024/25.

- Tutshi-Moon Pumped Storage Project – Phase 1: This project would provide renewable capacity to address the existing and forecast capacity shortfall under the N-1 planning criterion. YEC stated that this project could potentially provide 35 MW dependable winter capacity starting in the 2028-29 winter season. Federal funding was identified as a critical requirement for this to be affordable for ratepayers and to minimize risks.

- New 20 MW Wind Project: YEC submitted that this project could provide a new 20 MW wind resource in 2025/26 to meet the higher energy requirements over the planning period. This resource option would not provide dependable capacity.

YEC summarized its position by stating that no feasible renewable resource alternatives to the BESS Project have been identified within the expected time period for completion of the project and that the temporary rented diesel option or permanent new diesel development remain the only feasible alternatives to provide dependable capacity to meet the utility's requirements.[105]

Yukon Conservation Society

YCS did not discuss this aspect of the Minister's Terms of Reference.

John Maissan

John Maissan stated that the only reasonable alternative to the BESS Project is a 20 MW or larger diesel thermal generation plant as noted in the past LNG project proceeding. In Mr. Maissan's view, in the public consultation on a proposed new thermal plant, the public opposition to such a project would be significant. Mr. Maissan added that a thermal alternative is also contrary to Yukon government policy, citing YEC's response to information request YUB-YEC-1-1 (f) and (g). Further, Mr. Maissan noted that a thermal plant must be diesel rather than LNG because diesel generators have a much better ability to restore the grid from outages, and that a thermal plant would not provide ratepayers with the savings from reduced thermal generation the way that the BESS Project can. Nor would a thermal plant provide the reliability, load loss stabilization, and black start and outage restoration benefits that the BESS Project provides. Mr. Maissan concluded that a diesel thermal plant is not an advisable alternative to the proposed BESS Project given that a thermal plant would lack the financial and other benefits that the BESS will provide.[106]

Utilities Consumers' Group

UCG stated that YEC confirmed it was YEC's board of directors that decided not to pursue a permanent solution to the capacity gap on the YEC system (i.e., a large new permanent diesel) and instead instructed management to focus on renewable projects. UCG submitted that this direction prevented the consideration of diesel- or LNG-fueled generation alternatives to the BESS Project.[107] UCG added that a capacity shortfall arose because YEC did not previously establish a plan to pursue overhauling all of their diesel generators as they were retired. If YEC had established an efficient plan of thermal plant overhaul and replacement, UCG argued that YEC would not find itself in the position of having to use and replace rented diesel generation equipment and having N-1 capacity backup issues.[108]

[105] YEC Application, PDF pages 33 to 35.
[106] John Maissan Final Argument, PDF page 10.
[107] UCG Final Argument, PDF page 14, paragraph 78.
[108] UCG Final Argument, PDF page 14, paragraph 79.

Yukon Energy Corporation

In its final submission, YEC stated that the BESS Project provides 7 MW of dependable N-1 capacity on a timely basis, with benefits not available through other alternatives.[109] Couching its position in terms of not relying on new fossil fuel alternatives and near-term renewable resource alternatives, YEC said there were no reasonable alternatives to the BESS Project and that a new 20 MW thermal plant is not a viable option.[110] YEC added that maintaining the status quo is also not a viable option and permanent solutions are needed.[111] Aside from the Atlin Hydro and Moon Lake Pumped Storage projects, temporary rental diesels or a permanent new thermal development remain the only feasible alternatives that would provide the dependable capacity required to address the N-1 dependable capacity shortfall. The BESS Project's operating reserve use benefits enable it to provide material ratepayer cost savings relative to both the diesel rental and permanent thermal alternatives.[112]

YEC stated, with respect to longer term projects, that the two dependable capacity hydro renewable projects identified for development within 10 years are each subject to securing material federal grant funding and, even if they are developed, they will not remove the ongoing need for the other dependable capacity projects such as the BESS Project.[113]

Board Views

The Terms of Reference require recommendations on reasonable project alternatives or alternative ways of undertaking this project. It is clear from the submissions of all parties that some form of diesel generation is the only viable alternative to the BESS Project, at least in the near term. In the oral hearing, two YEC witnesses noted that the benefit to the BESS Project is operating reserve, as demonstrated by the following testimony:

> … N-1 is a one-in-10-year event. So it's really important to keep in mind, you have to look at the costs of the alternatives, where they're spending most of their time just sitting there not doing anything, as well as other use cases, which we presented in that table when we talk about the operating reserve, used savings, and the peak shifting uses. So it's not just the N-1 that justifies the project.[114]

In the Application, YEC submitted its alternatives to the BESS Project but stated that no feasible renewable resource alternatives to the BESS Project have been identified within the relevant time period and that the temporary rental diesel option or permanent new diesel development remain

[109] YEC Final Argument, PDF page 19.
[110] YEC Final Argument, PDF page 20.
[111] YEC Final Argument, PDF page 20.
[112] YEC Final Argument, PDF page 19.
[113] YEC Final Argument, PDF page 20.
[114] Transcript Volume 3, PDF page 31, lines 6 to15.

the only feasible alternatives.[115] YEC identified some of the facilities projects in its 10-Year Renewable Electricity Plan as alternatives.

YEC has been renting diesels to cover its capacity shortfall. A YEC witness stated in testimony regarding the planning respecting the capacity shortfall: "So we plan, essentially, for N-1 once every 10 years. That's what we anticipate the frequency to be."[116]

The rental option to cover capacity shortfall is the status quo option. YEC started renting diesels for the 2018-19[117] winter peak and it expects to continue renting diesels up to and including the 2028-29 winter peak.[118] YEC expects diesel rental costs to continue for 10 years.

Rental or purchased diesel units

The issue of rental or purchased diesel units is also discussed in Section 3.1 of this report. YEC compared the BESS Project to the rented diesel alternative, and based on this comparison, YEC concluded that the BESS Project was economically superior[119] and met the primary criteria N-1 capacity shortfall.

When asked whether there were any operational concerns with the continued use of rented diesel fuel generators and the economics of the two alternatives, YEC stated that it looked at the capacity gap, the expected length of the capacity gap, and future plans to bring capacity additions online. In YEC's view, through that assessment, the rental of diesels was a viable solution. Operationally, however, since that assessment, YEC has learned that the rental units are not always available, and so two additional spares are required. [120]

YEC witness testimony provided additional insight into the utility's reasoning, and some of these reasons are summarized below:

- The rental diesel units are not as reliable as YEC would like them to be.[121]
- Rental units are not perfectly configured for utility service. The decision for rental of diesel units versus the decision for permanent purchase are quite different.
- If YEC were investigating the specifications for something to place on the YIS that it absolutely needed to have because they're there for the N-1, it would not look at something that had the kind of use history that the rental units have.
- The alternative would be to look at a permanent diesel facility, i.e., larger facility options.[122]

[115] YEC Application, PDF page 35.
[116] Transcript Volume 3, PDF page 55, lines 23 to 25.
[117] YEC consolidated responses, YUB-YEC-1-17(c), PDF page 158.
[118] Transcript Volume 1, PDF page 173, lines 4 to 10.
[119] E.g., see YEC Application, PDF page 43, Table 4-3, Annual Ratepayer Impacts from BESS.
[120] Transcript Volume 1, PDF page 86, lines 3 to 23.
[121] Transcript Volume 1, PDF page 123, lines 18 to 23.

YEC's Application and testimony support that the rented diesels are not a preferred alternative to the BESS Project. The BESS Project has a higher levelized cost of capacity than rented diesel units.[123] However, YEC states that the BESS results in a net present value benefit to ratepayers and the BESS is expected to offset the use of four diesel units. On review of the record, YEC has sufficiently demonstrated that the BESS Project is a preferred alternative to rental diesel units.

Diesel (thermal) plant

Another alternative to BESS is to construct a new diesel plant. This is also discussed in Section 3.1 of this report. In a previous Board Order, the Board found that YEC has supported its case that added capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity.[124]

In response to an IR in this proceeding, YEC stated:

> The YUB reviewed planning for the new 20 MW diesel plant project during the 2017/18 GRA, and noted in Appendix A to Order 2018-10 that it was not persuaded that the project was the only way to address the predicted capacity shortfall, and that YEC should not proceed with the project without a detailed business case that considers the alternatives to the project.[125]

YEC did not correctly summarize the Board's views. The Board's comments were not a condemnation of building a 20 MW diesel plant project; rather, the Board was reminding YEC that it should provide a business case with adequate support for the project.

In the Board's view, YEC did not fully consider the acquisition of purchased diesel as an alternative to compare with the BESS Project, partly because of direction from its board of directors to focus on renewable options. Some social license considerations were engaged as well. As a result, the benefits and costs of purchased diesel were not examined in detail to discount a new diesel plant as an equal or preferred alternative. YEC noted that one particular advantage of the BESS Project over diesel was that "it has almost instantaneous ability to ramp to full output; whereas a new diesel plant can take several minutes to ramp up. And so, a BESS has a much greater ability to keep the grid stable and operating versus a diesel engine."[126]

Although it is not YEC's preferred alternative, YEC confirmed in testimony the ability of diesel to mitigate loss from N-1 events. YEC confirmed that both the BESS and a diesel alternative are appropriate solutions to meet N-1 criterion, but the BESS provides a faster solution to prevent a blackout. Both would work equally well over a longer duration event. [127]

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[122] Transcript Volume 2, PDF page 43, line 21, to PDF page 44, line 2.
[123] YEC Application, PDF page 21.
[124] Appendix A to Board Order 2018-10, PDF page 94.
[125] YEC consolidated responses, YUB-YEC-1-37(b), PDF page 255.
[126] Transcript Volume 1, PDF page 159, lines 3 to 14.
[127] Transcript Volume 2, PDF page 38, line 3, to PDF page 40, line 8.

Further, in response to an IR, YEC showed that the levelized cost of capacity for the purchase of a diesel plant was less than that of the BESS option.[128]

If diesel is to provide capacity for a one-in-10-year event (N-1), then the generation unit would likely be idle most of the time. This means there should be less environmental implications from an emissions perspective as compared to diesel that is always running. YEC also did not investigate or state whether government funding would be available for a new diesel plant.

Despite these limitations, it is the Board's recommendation that the Minister can consider that YEC explored alternatives to the BESS Project, and YEC has provided a sufficient economic basis for the BESS Project to proceed compared to the alternatives identified by YEC. The Board has provided its views on a diesel plant for additional capacity because there are benefits to this alternative, particularly from an economic perspective, and considers that a diesel plant should not be disregarded by YEC's board of directors as a viable alternative to meet future system capacity. In reviewing the totality of the evidence, the Board is satisfied that the Minister can accept that the BESS Project is an acceptable and economic alternative as part of YEC's system planning for generation.

Location

In addition to reasonable project alternatives, the Terms of Reference ask about alternative ways of undertaking the project. The Board considers alternative siting to fall under this category. The Board notes that requiring the project to be located on settlement land, and having only one option outside city limits which ultimately was not selected, may have resulted in additional and material costs to the ratepayer. The selected location within municipal boundaries includes approximately $6 million to $7 million[129] in municipal taxes over the life of the project.

Alternatively, there may have been appropriate locations that do not involve lease costs or tax costs that were not sufficiently explored — for example, the unoccupied Crown land adjacent to the Takhini substation. Choosing a location on First Nation settlement land within the City of Whitehorse may have eliminated lower cost options.

[128] The table in response to YUB-YEC-1-30 (PDF page 231 shows the estimate LCOC of a diesel purchase to be $186/MW compared to $235/MW for BESS. YEC provided an update to this in undertaking #7, however those costs and assumptions were not tested nor did YEC explain why such scrutiny was not provided for the original IR response given that a comparison between BESS, rented diesel and purchased diesel were requested. Nor did YEC consider the sale of the purchased diesel when N-1 capacity criteria is met through other renewable energy projects identified by YEC to occur in subsequent periods.

[129] Transcript Volume 3, PDF page 36, line 12, to PDF page 37, line 1.

4.5 Impacts of the Debenture Investment Opportunity on YEC and Ratepayers — Term of Reference 3.e.

The Minister's Terms of Reference requested the Board to report on and make recommendations about the necessity for the BESS Project, among other matters, with particular regard to:

> 3.e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping Traditional Territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.[130]

YEC's Application noted that YEC engaged both First Nations (TKC and KDFN) in quarter 2 of 2020 and a trilateral committee was formed:

> "…for sharing Project information, assessing three alternative KDFN and TKC sites for the Project, and negotiating benefits for both First Nations from the Project. The Project Committee met regularly thereafter in 2020 with a particular focus on the work required to recommend a preferred site and to review a draft Term Sheet that evolved to include a debenture investment opportunity for both TKC and KDFN based on 25% of the equity portion of YEC's net rate base cost of the BESS project."[131]

YEC stated that First Nation debenture investment for facilities projects have occurred for past facilities. However, in the past, the debenture investment opportunities were made with Yukon Development Corporation and were therefore not subject to Board review.

For the BESS Project, the investment opportunity is being made directly with YEC. YEC added that, although there is no legal requirement to provide any First Nation with an investment opportunity related to the specified YEC facilities projects, past investment opportunities have been, or are currently, generally provided as part of First Nation engagement, involvement, and support for the project's development.

The debentures or details of the agreements with KDFN and TKC were not available for the Board's review because not all negotiations and agreements with the First Nations had been finalized. YEC expected that the debenture agreement itself would be a straightforward document.[132]

In addition, YEC summarized the key terms to the First Nation debenture investment in the Application as:

> 1. KDFN and TKC will each be offered the opportunity to provide a loan to YEC in accordance with the following principles:
>
> > a. YEC's Net Rate Base Cost for the Project is YEC's final capital cost for developing the Project less any funding contributions to YEC for the Project and any costs disallowed by the YUB from inclusion in rates.

[130] Minister of Justice's Terms of Reference, PDF page 3.
[131] YEC Application, PDF page 22.
[132] Transcript Volume 2, PDF page 82, line 20, to PDF page 83, line 2.

> b. The BESS Equity Cost is 40% of the Net Rate Base Cost and reflects the portion of the Net Rate Base Cost that is financed by YEC equity.
>
> c. KDFN and TKC will each be offered the opportunity to provide a Loan Investment of up to 25% of the BESS Equity Cost. The following example outlines the process, assuming a final BESS net rate base cost of $15.2 million after grants:
>
> > i. Assuming YUB approval of these costs, YEC's Net Rate Base Cost would be $15.2 million and this would be funded by 40% equity [the BESS Equity] of $6.1 million and by 60% long-term debt of $9.1 million.
> >
> > ii. KDFN and TKC would each have the opportunity to provide a Loan Investment of up to $1.52 million, i.e., each up to 25% of the $6.1 million BESS Equity Cost.
>
> 2. The Loan Investment opportunity will be available for a specified period after the Project is in service and YEC's final net rate base (after contributions and YUB review) is determined by YEC and communicated to KDFN and TKC.
>
> 3. The term for each Loan Investment will be based on the remaining portion of the expected asset life.
>
> 4. YEC will provide the following annual payments to KDFN and TKC with regard to each of KDFN and TKC's Loan Investment:
>
> > a. Repayment of principal at equal annual amounts over the Term; and
> >
> > b. An annual return on the Loan Investment balance then applicable times YEC's actual final rate of return on equity (actual percentage return for a completed fiscal year) for YEC's utility regulatory income for the completed fiscal year most recently filed with the YUB (YEC's last approved equity return included in rates is 8.70%).[133]

YEC added that the debentures would be treated as long-term debt given the nature of the financial instrument. Noting that the equity return paid on this instrument is well above the market rate for long-term debt, for the purposes of rate-making, YEC would treat this investment as equity to maintain the 60:40 debt-to-equity capital structure for YEC that the Board has previously approved. To maintain YEC's debt-to-equity ratio, YEC committed to execute the necessary transactions with YDC to maintain the 60:40 ratio on an annual basis.

YEC advised that any rate applications to the Board will show this debenture as a component of equity for revenue requirement determination, thereby causing no net impact to ratepayers from this transaction.[134]

[133] YEC Application, PDF pages 22 and 23.
[134] YEC Application, PDF page 23.

Yukon Conservation Society

YCS did not provide submissions on this issue.

John Maissan

John Maissan stated that the evidence indicates that the debenture investment opportunity has no impact on YEC or on the ratepayers of Yukon. He submitted that he was in full support of this opportunity and YEC decisions to contribute to these efforts by locating the BESS Project on a very suitable parcel of KDFN land. He recommended that the Board support this debenture investment opportunity in its report to the Yukon government.[135]

Utilities Consumers' Group

In its final submission, UCG expressed several concerns with the debenture investment opportunity.

UCG was concerned that YEC only considered First Nation land with the goal to create an opportunity for a land lease with the First Nations.[136] It submitted that YEC failed to do a proper market review of available locations and properly consider the costs of such decisions on ratepayers.[137] UCG disagreed with YEC's position that the land "is not a factor because YEC is using market-based costs so ratepayers would be indifferent because they would pay the same whether it was on settlement land or not."[138] UCG submitted that, given that YEC does not know what costs will ultimately be imposed by the First Nations or what type of longer term commitments will be put in place, there will be a cost burden to ratepayers due to this decision by YEC.[139]

Regarding the debenture investment opportunity, UCG stated:

> UCG questions YEC's claim that the First Nation debenture investment proposed for this project will enable Yukon First Nation investment without any impact to ratepayers. The fact that the net benefits to Yukon ratepayers could easily be negative for the majority of the life of the proposed BESS is obviously a negative impact on ratepayers no matter how YEC spins the form of Yukon First Nation investments.[140] (Footnote removed)

UCG also submitted that YEC implied that the cost of the First Nations' benefits will be in excess of the $100,000 identified in the project budget outlined in Schedule B of the Transfer Payment Agreement because the project budget far exceeds the $25 million assumed in the Transfer Payment Agreement.[141]

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[135] John Maissan Final Argument, PDF pages 10 and11.
[136] UCG Final Argument, PDF page 15, paragraph 87.
[137] UCG Final Argument, PDF page 15, paragraph 88.
[138] UCG Final Argument, PDF page 15, paragraph 89.
[139] UCG Final Argument, PDF page 15, paragraph 89.
[140] UCG Final Argument, PDF page 16, paragraph 94.
[141] UCG Final Argument, PDF page 16, paragraph 95.

UCG finalized its position on this issue by concluding:

> While YEC testified that it is "very hard" to find a development site that's actually better situated or on Crown land, that doesn't mean that more time shouldn't be put into keeping site-related costs as low as possible. It appears YEC is trying to avoid taking the time necessary to fully examine all options available. The unknown impact over the next couple of decades of property taxes (starting at $7 million) is a significant issue for ratepayers.[142] (Footnotes removed)

Yukon Energy Corporation

In its final submission, YEC stated that "First Nations' support for the Project is important given its location and YEC's desire to provide economic benefits to First Nations."[143] YEC also added that the "BESS Project is the first time when Yukon Energy - rather than Yukon Development Corporation - is providing a debenture investment opportunity in a YEC project"[144] and that the opportunity closely aligns with YDC's precedent on other Yukon projects such as Mayo B and the Whitehorse LNG.

YEC added that the debenture is a loan and that the return to the lender will be based on YEC's actual return on equity and will be included in YEC's equity return for rate setting purposes. YEC witnesses testified that there will be no impact on ratepayers.[145] Finally, YEC submitted that there will be an opportunity for the Board to review BESS Project costs including the debenture costs prior to those costs being included in rates.[146]

The nature of the debenture investment opportunity is best described as:

- Not a traditional loan in that YEC would not normally require a debenture with a rate based on its return for equity.
- Structured as a traditional loan instrument. Equity components are normally provided by the shareholder, YDC, through direct investment or accumulated earnings.
- The debenture investment opportunity does not create an ownership interest for the two First Nations.
- Historically, YDC entered into these kinds of transactions with First Nations on prior YEC projects. YDC did not have the ability to enter into this type of transaction this time.

[142] UCG Final Argument, PDF page 16, paragraphs 96 and 97.
[143] YEC Final Argument, PDF page 24.
[144] YEC Final Argument, PDF page 25.
[145] YEC incorrectly referenced page 125 of the transcripts, whereas the testimony from Mr. Mollard started at Transcript Volume 1, PDF page 135, lines 7 to 12. Further testimony occurred at Transcript Volume 2, PDF page 86, lines 2 to 13.
[146] YEC Final Argument, PDF page 25, and Transcript Volume 2, PDF page 85, line 24, to PDF page 87, line 22.

- The YEC board of directors made the decision for YEC to enter into this type of transaction with the understanding that the Board would approve this type of transaction.[147] [148]

Board Views

The Minister asked the Board to assess the impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping traditional territory of TKC and KDFN and the benefits of TKC and KDFN support for the BESS Project's development at this time.

During the hearing, the Board asked questions about the selected location and possible impacts on ratepayers. The Board agrees that situating the BESS Project on First Nation land, from a cost perspective, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market or situating it on Crown land outside of the limits of the City of Whitehorse. Situating it within the City of Whitehorse will result in additional tax costs.

The Board notes that UCG was the only participant that raised concerns about YEC considering only First Nation settlement land or the debenture investment opportunity for the BESS Project. It did so from an economic and ratepayer perspective.

YEC also stated that, from its perspective, structuring the arrangement as debenture is a benefit to the First Nations and that ratepayers will be indifferent, i.e., the debenture agreement will not harm or benefit ratepayers.[149]

With YEC as the counterparty to the debenture agreement, YDC is still directly impacted by such an agreement.[150] The Board would highlight to the Minister that it does not have transparency into the agreement with the KDFN and TKC and is relying on YEC's summary of key terms of the arrangements with the two First Nations for a debenture investment for the purpose of this report.

In general, a debenture is a debt instrument that pays interest at a higher rate than YEC's average long-term debt. The Board considers that the reasonable consequence of YEC's willingness to allow for adjustments that would be approved by YDC may result from a lower return on YEC's other net rate base to enable this debenture agreement to ensure that YEC maintains a 60:40 debt/equity ratio. From a purely regulatory perspective, it would be more accurate and simpler to treat the return on the debenture in excess of YEC's average cost of long-term debt as a disallowed expense, effecting the same net result to YDC's return while maintaining the overall integrity of YEC's accounting. It appears from the Application that YEC is willing to take on the

[147] Transcript Volume 2, PDF page 81, line 8, to PDF page 82, line 7.
[148] Transcript Volume 1, PDF page 135, lines 5 to 12.
[149] Transcript Volume 1, PDF page 135, lines 5 to 12.
[150] As noted by Mr. Mollard, YDC would be affected by either direct investment or accumulated earnings.

risk of a lower return on the other assets in order to undertake the BESS with TKC and KDFN involvement.

The accounting treatment of the debenture investment opportunity and associated costs to ratepayers are issues best addressed in a GRA. Based on the testimony of YEC's witnesses, the Board accepts YEC's commitment that ratepayers will not be adversely impacted by the debenture investment opportunity. On balance, the Board does not object to the debenture agreements, nor will it recommend any conditions on the debenture agreement, but it will carefully scrutinize YEC's commitment that the debenture agreements will not impact YEC's ratepayers, i.e., that the costs from the debenture arrangements are rate neutral. Conversely, the effect of only situating the BESS Project on First Nation land, from a cost perspective, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market.

The cost or benefit to ratepayers as a result of using First Nation land compared to privately procured land (outside municipal boundaries) or Crown land is unknown at this time. The Board is of the view that, since the land has not been openly procured, any potential premium paid for the use of the land, or additional costs for the transaction beyond a competitive market range, should be borne by the shareholder, YDC.

The costs for the land lease part of the project are not as significant as the other capital costs for the BESS Project, and as stated above, further review of the costs will occur in a future GRA before the Board. In these circumstances, the Board accepts the use of a debenture agreement between YEC and First Nations; however, YEC is expected to reflect the fact that it is a debt instrument in any regulatory filing with this Board. Further, YEC shall separately show the premium it is paying for this long-term debt relative to its other existing long-term debt in its future GRA applications and shall also show that the premium is not being recovered from ratepayers. The Board is of the view that, for future facilities projects, it is preferred that Yukon Development Corporation — as YEC's parent — be the contracting party for debenture agreements, as has been done for past Part 3 applications.

4.6 Building the BESS Project at this Time — Term of Reference 3.f.

The Minister's Terms of Reference requested that the Board report on and make recommendations about the necessity for the BESS Project and its timing and design, with particular regard to:

> f. Whether it is prudent to build the BESS project as proposed at this time.

Yukon Energy Corporation

YEC submitted it was the right time to build the BESS Project because it had secured government funding, reducing the costs that will be required to be recovered from ratepayers. YEC also highlighted the need for the BESS Project in mitigating capacity shortfall concerns and avoiding the rental of four diesel units. YEC submitted that ratepayer benefits would accrue starting in year 1 of the project. YEC advised that the BESS Project would contribute to meet the growing dependable capacity requirements, directly reduce YEC's reliance on thermal

generation, provide cost savings for ratepayers, and increase the reliability of electricity service to customers.

Yukon Conservation Society

YCS agreed that building the BESS Project is prudent at this time because it would eliminate the need to rent four diesel units and make the YIS more capable of delivering lower emission electricity to customers. YCS also stated that the ratepayer savings forecasted by YEC was conservative in nature, as it did not include volatility in diesel fuel prices in the future and the potential of applying a carbon tax to northern jurisdiction electricity providers.[151]

John Maissan

Mr. Maissan also agreed with the prudency aspect of the BESS Project, indicating that the information provided on the record strongly supported completing the project at this time. Mr. Maissan reiterated that YEC was conservative in its estimation of the benefits and agreed that the project would provide ratepayer benefits starting from year 1. Mr. Maissan also submitted that the reliability benefits were significant, even though they were not accounted for in the financial information for the project.[152]

Utilities Consumers' Group

UCG did not believe building the project was prudent at this time. It referred to Board Order 2018-10 in which the Board noted several risks and concerns with pursuing a grid-scale BESS Project, including concern that the technology had not been demonstrated in a northern climate. While UCG acknowledged that YEC made reference to BESS-type projects operating in northern Quebec and the Northwest Territories, UCG expressed concern that YEC did not address how successful these projects had been in achieving anticipated benefits and if any issues had arisen with these BESS installations. UCG submitted that YEC had not provided specific information regarding these other northern projects. UCG disagreed with YEC's position that information regarding costs, alternatives considered, or operating experience with these other projects would not provide any material assistance to the Board in its review of this Application.[153]

Board Views

Consistent with the Board's views provided in Sections 3.1 and 3.2 of this report, the Board finds there is a need for the BESS Project. In addition, YEC's funding procured from the federal government for the BESS Project makes it more affordable for ratepayers.

However, the Board does not consider it appropriate at this time to respond to the Minister's request for a recommendation on whether it would be prudent to build the BESS Project as proposed. The question of prudence is a key criterion that the Act requires the Board to apply in

[151] YCS Final Argument, PDF page 6.
[152] John Maissan Final Argument, PDF page 11.
[153] UCG Final Argument, PDF pages 16 and 17.

considering GRAs, and if the Board were to comment on the prudence of the BESS Project outside of GRA proceedings, any such comments could be challenged as prejudging matters that are best left for a GRA decision.

In any event, and as discussed earlier in this report, the uncertainties and insufficiency of information upon which the BESS Project proposal is predicated do not provide the Board with sufficient evidence on which to make an assessment of prudence, even absent the constraint mentioned above.

For these reasons, the Board declines to make any recommendation in response to subparagraph 3.f. of the Terms of Reference.

5. BOARD FINDINGS AND RECOMMENDATIONS

Specific aspects of the project to be reviewed

The Terms of Reference required the Board to report on, and make recommendations about, the necessity for the BESS Project and its timing and design (Section 3). A summary of the Board's findings on specific aspects of the project to be reviewed, as identified in the Terms of Reference, are as follows:

> 3.a. The public need for the BESS Project under various reasonable electric load forecasts, including near-term requirements related to industrial and non-industrial loads, and the effect of the Project on the rates of customers and the reliability of electricity service provided to customers.
>
> - The Board finds a near-term need for the BESS Project.
> - Given that the BESS Project is in a preliminary stage, there are too many uncertainties for the Board to make a recommendation on the effect of the BESS Project on final rates.
> - The BESS Project can provide operating reserve for the grid when excess water is available.
>
> 3.b. The capability of existing and currently committed and expected generation and transmission facilities, including thermal generation facilities, to provide reliable electric power generation to meet the forecast load requirements and YEC's capacity planning criteria and the effect of the BESS Project on this capability.
>
> - The Board accepts that the BESS Project would contribute to reliable electric power supply to meet the forecast future load requirements.
> - From the information that has been presented on this record, the Board is satisfied that the project will not hinder existing and currently committed (and expected) generation and transmission facilities. The BESS Project will provide N-1 capacity support, operating reserve support, and increased grid reliability.

3.c. The risks for the BESS Project and their potential impacts on rates for customers and on the reliability of electricity service provided to customers.

- The technical risks include a real risk of fire and a risk that the battery life of the lithium ion will not last 20 years.
- The Board does not find sufficient evidence to support YEC's assertions that there would be no significant ratepayer impact from costs associated with YESAA, NavCanada, and Transport Canada regulatory risks and approvals.
- As the BESS Project is a class 4 estimate (+/- 30% accuracy), there is a risk that the costs for the BESS Project may exceed the $31.7 million estimate.

3.d. What, if any, reasonable alternatives exist to the BESS Project or what alternative ways of undertaking the BESS Project with its selected technology might be advisable given reasonable load assumptions and risk assessments?

- Diesel generation is the only viable alternative to the BESS Project in the near term.
- The Board finds that the BESS Project is a preferred alternative to rental diesel units and an acceptable alternative to a new diesel plant.
- An alternative way of undertaking the BESS Project would include considering locating the project outside the City of Whitehorse.

3.e. Impacts on YEC and ratepayers of the debenture investment opportunity that YEC is providing to TKC and KDFN in recognition of the BESS Project's location on the overlapping traditional territory of TKC and KDFN and the benefits of TKC and KDFN support for this Project's development at this time.

- The Board accepts YEC's commitment that ratepayers will not be adversely impacted by the debenture investment opportunity.
- The effect of YEC's decision to only consider situating the BESS Project on First Nation settlement land, may lead to higher costs for ratepayers than would otherwise occur through obtaining land competitively in the market.

3.f. Whether it is prudent to build the BESS Project as proposed at this time.

- Any comment or recommendation the Board may make about the prudence of the BESS Project at this time could, in effect, prejudge what it is statutorily required to be considered at GRAs. Therefore, the Board declines the opportunity to make any such comments at this time.

Recommendation respecting certificates

The Terms of Reference state that the Board shall provide a recommendation on whether YEC should be granted an energy project certificate and an energy operation certificate for the BESS Project and, if so, whether the certificates should be subject to any terms and conditions and what these terms and conditions should be (Section 5).

Based on the above findings, the Board recommends that YEC be granted an energy project certificate and an energy operation certificate. There is a public need for the BESS Project, and the project would allow YEC to install new capacity with some other potential system benefits. The Board notes that the evidence that the BESS Project would result in savings to ratepayers is incomplete and inconclusive. As such, all estimates must be treated as preliminary. Any resultant savings and ratepayer impact cannot be determined at this time.

Making a recommendation about ratepayer impact at this stage in a process, with so many outstanding costs, is difficult. This is why the Board has put a great deal of emph asis on the prudence review of costs at future GRAs. The Minister will have to consider whether requiring additional transparency to the government, such as quarterly reporting to the Minister, is warranted before the final costs of the project are submitted to the Board for review in a GRA.

Other recommendations

The Terms of Reference state that the Board may make any other recommendations or provide any other information that it considers advisable in the circumstances (Section 6). As noted in Section 2.1, the Board recommends that Ministerial approval of this project, if granted, is informed by governmental and other public policy issues outside of the Board's jurisdiction as an economic regulator. Specifically, decision-making criteria related to First Nation economic development opportunities and climate change concerns are beyond the Board's authority set out under the *Public Utilities Act*.

ISSUE:

REFERENCE: Application, Table 4-1, page 20, PDF page 23Issue: Non-industrial peak and dependable capacity

QUOTE:

QUESTION:

a) Under the category “Non-industrial Peak”, please explain what “EV Peak” is.

b) Under the category “N-1 Event”, please explain the inclusion of “Loss of AEY Haines Junction diesel” and “Haines Junction peak”.

ANSWER:

(a)

EV Peak relates to the peak demand forecast related to electric vehicle use. It is a specific load forecast growth element addressed in Table 2 of YEC’s 10-Year Renewable Electricity Plan (see YUB-YEC-1-32, Attachment 1).

(b)

On the YIS, Haines Junction is supplied by a single feeder from the Aishihik Hydro station. Therefore, during an N-1 event (loss of the Aishihik plant or transmission line), YEC would be unable to supply the load at Haines Junction nor can YEC rely on the local diesel, so both are excluded from the calculation.

ISSUE: **Historical records**

REFERENCE: **Application, footnote 34, page 22, PDF page 25**

QUOTE: "See Section 2.1.3 of this Submission. The LTA energy generation estimate for the Project deliveries to YEC was prepared by SNC Lavalin, retained by THELP, based on available historical water records (1963-1993; 2015-2019) as reviewed in Appendix A, Table A1. The Project LTA energy generation in Appendix A, Tables A1 and A3-1 for winter deliveries to YEC at Jakes Corner reflects the average Atlin Project hydro generation during the Winter Period (Jan. 1 to May 31, Sept. 1 to Dec. 31) for all water records, while the low water year winter generation deliveries reflect the lowest hydro generation in water year 1978. The transmission losses between the Atlin generation location and delivery point at Jakes Corner is estimated to be at around 2.7%. Additional losses are added that reflect losses in YIS system which is assumed at 6.2% based on losses approved for ATCO Electric Yukon in its most recent GRA (assumes AEY System Upgrades will result in continuation of past average losses despite the material increases in energy being transmitted on this system)."

QUESTION:

a) Why are historical water records from 1994-2014 not included in the LTA energy generation estimate?

b) How accurate is the assumption that, with higher load, the assumed AEY System Upgrades will result in the continuation of past average losses? Please explain the basis for the assumption.

ANSWER:

(a)

YEC understands that adequate historical water records are not available from 1994-2014. The initial feasibility studies on this Project prepared for THELP by Morrison Hershfield and KGS Group were able to develop a flow and power hydrological simulation model for

Pine Creek flows based on comparison to Gladys River area's nearly complete 32 years of recorded flows by Water Survey of Canada from 1964 to 1993. It was concluded that the 30 year synthetic flow series from the Gladys River provides a reasonable estimate for long-term flows in Pine Creek. The feasibility study was also able to utilize monitoring initiated in September 2014 of Pine Creek catchment flows.

(b)

The 6.2% losses assumed for AEY transmission reflect historical information, and variances are expected after AEY System Upgrades and addition of the Atlin deliveries. However, the AEY design for System Upgrades assumed Atlin deliveries at 10.575 MW (i.e., higher than the EPA allowed maximum of 8.5 MW) and reflected the need to ensure expected AEY losses do not exceed 8.8%. Final selected AEY Systems Upgrades design and Atlin load will affect the extent to which actual losses are materially below the 8.8% design limit.

ISSUE: **Unknown reference**

REFERENCE: **Application, page 24, PDF page 27**

QUOTE: "The BESS and the Project each can reduce the need for rented diesels – however, the Moon Lake pumped storage project, when developed in combination with BESS and the Project (as well as other developments assumed in Table 3-1), is the only identified resource option aside from default new thermal generation that has the capability to remove the forecast N-1 dependable capacity shortfall and reliance on rented diesels."

QUESTION:

a) Table 3-1 is entitled "Summary EPA Energy and Capacity Pricing". What developments is YEC referring to in Table 3-1, or what table should YEC be referring to related to the above quote?

ANSWER:

(a)

The above quote includes a typo. The reference to Table 3-1 is incorrect. The correct reference is Table 4-1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning criterion: 2021/22-2030/31 Winter (kW).

ISSUE: **Rented diesels**

REFERENCE: **Application, page 24, PDF page 27**

QUOTE: "The only other alternative identified to date for meeting the capacity shortfall without rented diesels would be to develop additional permanent thermal (diesel) capability beyond the planned replacements of retired units. As reviewed in the BESS proceeding, the development of new permanent diesel plants is not supported by stakeholders and is also not in line with goals outlined in Yukon government's draft 'Our Clean Future: A Yukon strategy for climate change, energy and a green economy.' As reviewed in Section 4.2 below, EPA impacts on customer rates are designed to mirror or improve upon the impacts to be expected with a permanent thermal generation option."

QUESTION:

a) Explain the steps YEC took to review and the analysis undertaken regarding the diesel rental option.

b) Describe the steps taken and analysis performed regarding the purchase of a larger diesel option (for example, 20 MW) and later sale of that unit when the greenfield projects are completed (Atlin, BESS, Moon Lake). What is the impact of these options on GHG emissions?

c) Disclose all documents within YEC's control, both public and internal, relating to the comparative benefits and disadvantages of thermal generation options, including rental diesel generators, purchasing portable diesel generators, and constructing a large (e.g. 20 MW) permanent diesel generator. Include all comparative financial benefits and disadvantages of each option.

d) Referring to the final paragraph of 4.2, how many "stakeholders" were opposed to the permanent generator option and what specific interests did these stakeholders represent? Were these stakeholders full informed of the other options – e.g. continuing use of rental diesel generators? Were the stakeholders informed about the comparative electrical rate impacts associated with the available options?

ANSWER:

(a)

YEC did not undertake any new analysis regarding the diesel rental option. Dependable capacity for thermal generation was benchmarked against other permanent generation options (i.e., new greenfield diesel) and not against a rented diesel option. As reviewed in section 4.1.1 of YEC's Submission (page 19), the Board in its BESS Report was "…persuaded that only relying on rented diesel generators would be challenging and would not be a reliable way of closing the capacity shortfall gap."[1]

(b) and (c)

Yukon Energy reviewed in the 2021 GRA proceeding (as well as in the prior BESS Project Part 3 Application proceeding) its earlier investigations of thermal generation options (permanent and rental diesels). YEC has not carried out any new investigations, given its need to focus on implementing the 10-Year Renewable Electricity Plan, including the BESS Project, replacement of retired diesel generation, the Atlin EPA, and seeking funding needed to carry out planning for the Tutshi-Moon Lake Pumped Storage Project and the new transmission connection of Whitehorse-Skagway to enable sale of surplus summer YEC renewable energy to displace cruise ship diesel generation. Major new permanent diesel options (beyond replacement of retired units) are only likely to be revisited within the next decade in the event that the Tutshi-Moon Lake Pumped Storage Project (or some equivalent renewable option) is confirmed not to be feasible at this time.

A summary of the relevant record based mainly on the 2021 GRA proceeding is provided below in response to these questions.

Rented Diesels as Feasible Option for Near-Term Capacity Shortfall

YEC has conducted several detailed assessments of more permanent options for addressing the dependable capacity shortfall since diesel rentals were first installed for the 2017/18 winter – including YEC's recent 10 Year Renewable Electricity Plan completed in 2020 and its earlier more detailed assessment of a 20 MW new diesel plant and other options in YEC's 2016 Resource Plan.

[1] YUB Report to the Yukon Minister of Justice - YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Energy Battery Storage System (BESS) Project, June 30, 2021, page 11. A copy of this report is provided at YUB-YEC-1-32, Attachment 2.

In summary, the evidence confirms that Yukon Energy has diligently assessed permanent options to address the capacity shortfall:[2]

- YEC's 2016 Resource Plan issued in spring of 2017 was the first time the magnitude of the current dependable capacity shortfall was identified as a major issue; the 2016 Resource Plan reviewed extensively the possible permanent options. As a result of that extensive review the Plan recommended a number of possible permanent options including a new 20 MW diesel plant (with provision for future expansion to 30 MW), a BESS project, a third LNG unit, dependable capacity DSM, and potential new dependable hydro capacity options.

- YEC first rented diesels for the following winter of 2017/18. It was without question the only feasible option for that winter to address the then identified N-1 dependable capacity shortfall. YEC has continued to pursue diesel rental thereafter as required each winter to address the forecast N-1 dependable capacity shortfall until permanent solutions can be brought into service. In this context, rented diesels have become the default option used to assess the cost effectiveness of proposed permanent solution options such as the BESS project and permanent diesel replacement options.

- Following the 2016 Resource Plan, YEC diligently pursued permanent solution options, including the 20 MW new diesel plant, the third LNG unit, the BESS project, dependable capacity DSM, and potential new dependable hydro capacity options. Given these actions there is no basis for suggesting that YEC was imprudent or irresponsible in its planning to address the dependable capacity gap.

- As a result of detailed planning assessments (including consultation and engagement on the 20 MW new diesel plant site options), YEC's Board in 2019 rejected that alternative for further consideration and directed that new permanent thermal options focus on diesel replacement at existing plants.

- Yukon Energy is currently diligently acting to implement the 10 Year Renewable Electricity Plan that includes diesel replacement options at existing diesel plants, renewable capacity alternatives including BESS, dependable capacity DSM, and

[2] See Mr. Hall, 2021 GRA Transcript pages 450 to 454; 2021 GRA CW-YEC-2-6(a) and (b).

dependable hydro capacity provided by the Atlin Hydro Expansion project and the Tutshi-Moon Lake Pumped Storage project.[3]

- Yukon Energy has confirmed that as at 2019, when the decision was made to not pursue the 20 MW new diesel plant option after completion of detailed planning work, it would have taken at least four years to plan, permit and construct a new 20 MW or 12.5 MW diesel plant, i.e., such a new diesel plant could only have been available in 2023 at the earliest.[4] In other words that option -- even if it was pursued -- could not have been in service during the 2021 test year.

In summary, the evidence confirms that rented diesels are the only feasible option for Yukon Energy to address the dependable capacity gap for the 2021 GRA test year and other near-term periods. Further, the evidence confirms that this situation exists notwithstanding YEC's ongoing diligent pursuit of new permanent solution options to address the dependable capacity gap.

Further, the evidence also clearly demonstrates the challenges that Yukon Energy faced in successfully securing sufficient additional rental diesels (including moving to place sufficient units at Faro) by winter 2020/21 following the lessons learned from the extended cold spell in January 2020.[5]

Renting for the long-term, however, is not a preferred option. As noted in response to "a", renting as a long-term option would be challenging and not a reliable option – it would also likely be more costly than a permanent diesel option.

Renting Option is Preferable to Possible Ownership that assumes subsequent Sale

[3] 2021 GRA CW-YEC-2-6(a) and (b). These investigations were detailed in the response, with reference to 2021 GRA CW-YEC-1-36(a) Attachment 1 copy of the YEC 10-Year Renewable Electricity Plan completed during 2020. Ms. Milojevic also reviewed the extensive work done by YEC to identify and cost options for the 2016 Resource Plan and the current 10-Year Renewable Electricity Plan, 2021 GRA Transcript pages 458-460.

[4] Mr. Hall, Ms. Milojevic, 2021 GRA Transcript pages 454-456.

[5] Mr. Gazankas, 2021 GRA Transcript pages 445-446.

Questions were raised in the 2021 GRA Exhibit C-6 and in 2021 GRA cross examination by the Board[6] relating to the possibility of purchasing rather than renting required diesel units, with an assumed later sale when greenfield projects are completed.

YEC has provided business case Levelized Cost of Capacity (LCOC) cost comparisons for new permanent dependable capacity project options (including permanent YEC owned diesels) versus rented diesels. These LCOC cost assessments confirm that diesel rental costs are reasonable in comparison with permanent diesel costs when these can be installed.[7]

Further, the evidence also demonstrates that rented diesels is a flexible year-by-year option that avoids capital cost commitments and related risks associated with asset ownership options. As such the LCOC comparison is directed at simply confirming the cost effectiveness of permanent solutions (when these are feasible to implement) relative to the rented diesel option, i.e., the LCOC assessment alone is not a useful indicator for assessing rented diesel costs for the 2021 test year.

As evidenced by the 10-Year Renewable Electricity Plan, YEC is actively pursuing a range of permanent dependable capacity options to remove the need for reliance on rented diesels as soon as this can reasonably be achieved within an effective long-term resource development plan – but as noted none of these options can displace the need for rented diesels in the 2021 GRA test year as well as other near-term periods.

Focusing then only on rented diesels, YEC has confirmed that purchase rather than rental of these units is not a prudent or practical option for the Corporation even when subsequent sale of the units is considered as a way to retain a degree of flexibility relative to “permanent ownership” options:

First, the current rental units are not the type of unit that YEC would ever seek to secure as permanent units. Further, and in any event – Finning (who is renting the units to YEC)

[6] Mr. Fortin, 2021 GRA Transcript pages 430-433.

[7] 2021 GRA CW-YEC-2-6(a) and (b). Diesel rental costs are indicated at $162.4/kW for winter 2021/22 for 27 MW (15 units for N-1 requirements), versus an LCOC (2022$) of $211/kW for 20 year life and $243/kW for a 40 year life. A 12.5MW YEC owned diesel plant option LCOC (2022$) with a 40 year life is estimated at $186/kW without property tax (Takhini site) and $212/kW with property tax (Whitehorse site).

has not made any proposals for YEC ownership and in some cases does not even own the units that it is renting to YEC.[8]

Second, Mr. Hall reviewed in the 2021 GRA proceeding in some detail why a purchase/sale alternative would not be a realistic or practical option that YEC could quantify adequately at the front end. He explained why he would not be comfortable getting into the business of trading diesel units pretty much on an annual basis, and why renting diesel units is an appropriate way to address relevant ongoing uncertainties as to the need for additional diesel units.[9]

> Briefly, I don't believe it's a realistic option that we would have been able to quantify economically in an adequate fashion at the front….
>
> Well, you can imagine that, you know, a strategy to rent, the rental costs are known at the front end. If we were to look at an option to purchase and then sell again in the future, we have to look at, firstly, you know, what certainty we have around those overall economics. Then the practicality of buying and selling units potentially on an annual basis.
>
> So I'll deal with each of those in turn.
>
> So the first thing about cost certainty, I know of no way that we could have confirmed the sale price of the units four, five, eight years down the track to an adequate level of certainty that our board would have been comfortable that we had a handle on the economics. So that's the first point. In terms of practicality, you know, I'll draw folks attention to Figure 20 again in the 10-year renewable plan….
>
> So you can see that the height of the hatched grey bars, the temporary diesel rental, varies over time. So you can see as additional resources are brought online through to 2024, so that would be the battery for example, plus the Atlin project, the number of rentals would drop. So we would be

[8] Mr. Mollard and Mr. Hall, 2021 GRA Transcript pages 305-306; Mr. Mollard, 2021 GRA Transcript page 431. Also Mr. Hall and Mr. Mollard, 2021 GRA Transcript pages 432-433 (Mr. Mollard also references here looking continuously for potential other rental suppliers than only Finning, who to date was the least cost rental supplier offering this service to YEC).

[9] Mr. Hall, 2021 GRA Transcript, pages 461-463.

> buying diesels, then selling them and then lo and behold after 2024 the height of that bar starts growing again. So we'd have to be buying again.
>
> So this whole idea of getting into the business of trading pretty much on an annual basis diesel engines, I mean, that's not our business, and I wouldn't be comfortable with us getting into that line of work.
>
> So given that profile of how many rentals we need, I think the idea -- renting gives you a lot more flexibility in terms of being able to determine the number of rentals on an annual basis and not having to buy and sell and trade those units.
>
> Also, as we've seen, there's some uncertainty to all of this, of course. So how quickly load grows, it has some uncertainty associated with it. And renting is an appropriate way of accommodating that uncertainty. If we were buying, we would be locking ourselves in, and then having to respond in a much more inflexible way to changes in circumstance.
>
> So I think if I look at those two factors together, the idea of buying rental units and then selling them again we just viewed as not being a practical solution for the company.

In summary, the evidence confirms that a potential diesel ownership option premised on subsequent resale when greenfield options are developed is not an acceptable option for YEC.

(d)

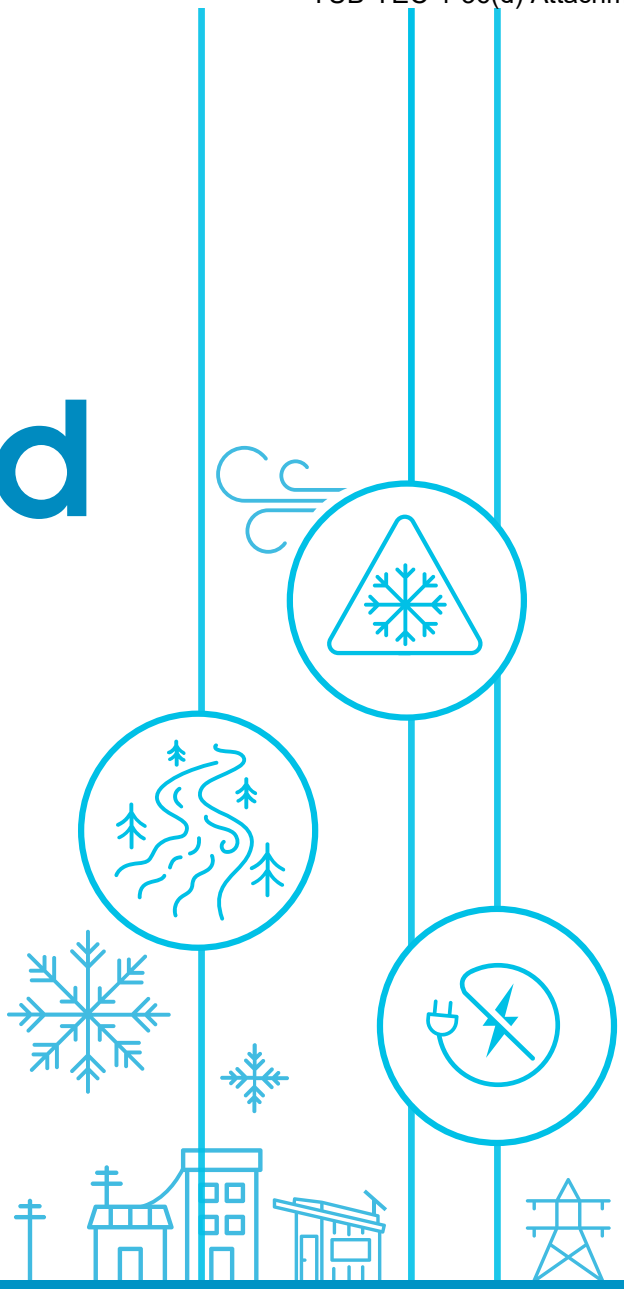
Yukon Energy has previously provided its results from the engagement process for the 20 MW new diesel plant option. Attention was directed at the specific options then under review. The summary in the referenced quote reflected the overall outcome.

The full report on the engagement process on the new greenfield 20 MW diesel plant project is attached (see YUB-YEC-1-36(d) – Attachment 1). The report highlights strong interest in ensuring that renewable options are fully explored and that permanent thermal generation options are minimized to the extent possible.

what we heard

PROPOSED NEW THERMAL GENERATION FACILITY

October 2019
public engagement summary



THERMAL ENERGY PART OF OUR
Future-Focused Portfolio

yukon energy

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executive summary

We are committed to providing sustainable, reliable and affordable power to Yukoners.

Yukon is growing, and so too is the demand for electricity. Population and economic growth in the territory, coupled with the increased use of electric heat in homes, has increased peak demands for power. Under certain emergency conditions, the demand for electricity is more than what is available.

In order to address these concerns, we are working to build our future-focused portfolio, a mix of new energy projects including hydro upgrades and enhancements, small hydro, battery storage, energy conservation programs, independent power producers, and a new 20 megawatt (MW) thermal generation facility in the Whitehorse area.

The new thermal facility would provide safe and reliable electricity quickly during:

- loss of hydro generation
- peak hours of consumption
- low water periods
- extreme low temperatures
- emergencies

Before the new thermal facility could move forward, we wanted to collect feedback from stakeholders and the public. In particular, our goal was to gather public input on the preferred location and fuel type (liquefied natural gas, diesel or dual-fuel) for the proposed facility.

We used a range of techniques to collect feedback, including a project-specific advisory committee, meetings with local First Nations and industry stakeholders, a public online survey, open houses, household visits, social media, and general emails and phone calls. This work took place between March and June 2019.

The Advisory Committee met three times between March and June 2019, providing us with their comments on the rationale and methodology of the project work. The Advisory Committee was not a decision-body of the project, nor did it approve our work. Their comments and feedback were used as input similar to other feedback received from other stakeholder groups and the public.

Senior leaders from our organization attended meetings and had discussions with the Kwanlin Dün First Nation, Ta'an Kwäch'än Council, City of Whitehorse, ATCO Electric Yukon and other industry stakeholders. The purpose of those discussions was to inform them of the need for the proposed facility, the locations and fuel options being considered and to gather their input.

We worked with the Yukon Bureau of Statistics to create a public online survey. This survey allowed individuals across the territory to access project information and provide input on the project at a time that best suited them. The survey was completed by 447 members of the public.

We also hosted four public open houses in the Whitehorse area between June 1st and June 6th. These open houses provided the public with the opportunity to provide us their feedback, ask questions and learn more about the project.

In addition to the survey and open houses, we visited approximately 175 homes and businesses within 800 metres of each of the proposed locations, and either visited or called an additional nine businesses with operations in the broader Takhini area to get their input on the project.

Finally, we distributed household mailers and ran ads on social media, specifically Facebook and Google, which informed people about the project and directed them to the project homepage on the website. Individuals were able to email or call us or comment on the ads to provide their feedback.

In order to make this information as useful as possible, we have considered all the input collected from the various engagement activities and have pulled out the key themes. They are not listed in order of importance.

1. Renewables, conservation and alternative solutions

There is a strong desire for Yukon Energy to pursue renewable energy projects. Participants expressed a desire for Yukon Energy to incorporate the latest technologies (e.g. battery storage, geothermal, nuclear, biomass, wind, solar) to increase the amount of renewable power generation, and to employ new programs and technologies to allow residents to conserve and better manage their electricity use.

Participants also expressed a desire for any new renewable project to capitalize on other opportunities and needs of the territory including managing garbage and recycling, increasing employment and business ventures (i.e., secondary businesses developed to support biomass).

2. Impact on residents

Participants who attended the Open Houses cited specific concerns about the proposed facility being located near their home and asked that the facility be located in less habituated areas. Participants cited specific concerns about noise levels, increased traffic, site safety, property values and general impacts to their quality of life. Specific to the proposed Takhini location, participants stated their objection to the site given its direct conflict with 'country living' and their sense of place. Residents in Riverdale tended to be concerned with noise levels from the facility should it be located in the existing Yukon Energy Diesel Plant.

3. Climate Change

Participants expressed a concern about climate change and the company's proposed use of liquefied natural gas (LNG) or diesel on the environment. Participants urged Yukon Energy to explore alternatives to fossil fuels to generate electricity siting concerns about emissions, pollution, air quality and the environment in general.

4. Go green, but if you must, use diesel

Participants urged Yukon Energy to use renewable energy sources instead of fossil fuels. But when asked specifically to choose between the use of LNG or diesel to fuel the proposed power plant, participants outlined a clear preference for diesel instead of LNG. Diesel was viewed to more effective for the integration of future renewables, while LNG was negatively viewed by many for its reliance on hydraulic fracking. A reliable fuel supply was also a consideration raised by survey respondents, which favours diesel given the established supply chain and storage facilities in Whitehorse.

5. Cost

Participants sited cost as an important factor for Yukon Energy to consider when choosing the location of the facility and whether to use LNG or diesel to fuel it. Respondents encouraged Yukon Energy to select the lowest-cost option in order to limit impact of the investment on rates.

6. Access during emergencies

When asked to choose between the five possible locations for the new power plant, respondents encouraged Yukon Energy to pick the location that could be accessed the most quickly and easily during emergencies. Respondents cited considerations such as proximity to the existing electrical grid and other back-up facilities, access to major roads, and how best to optimize operational efficiencies.

7. Rented vs. owned generators

While we did not explicitly ask for public input on the preferred ownership model for the new facility, participants who commented on the topic clearly expressed a desire for Yukon Energy to rent instead of own the proposed new generators. Renting was viewed as a way for Yukon Energy to continue to meet the short-term need for dependable power, while not committing to the use of additional fossil fuel generation in the long-term. It was also viewed that the lower up-front capital costs of the rental options would make more capital available for future investments in renewable supply options.

1.0 introduction

As Yukon continues to grow, so does the demand for electricity. Under certain emergency conditions, peak demand for electricity in Yukon outpaces what is available.

In order for us to continue to deliver sustainable, reliable and affordable electricity to Yukoners today and over the next 20 years, we proposed a portfolio of new renewable energy projects be built along with a new 20 MW thermal facility in or around Whitehorse. When complete, the portfolio would generate 95 per cent or more renewable energy on average over the next 20 years.

The proposed 20 MW thermal facility was identified as a critical piece of the portfolio because it would serve to provide safe, reliable and affordable electricity quickly during:

- loss of hydro generation
- peak hours of consumption
- low water periods
- extreme low temperatures
- emergencies

It would also provide a dependable and affordable way to meet peak demands for power that intermittent renewables like wind and solar cannot. It would also serve as a more permanent solution to our current practice of renting additional diesel generators each winter.

Given the limited amount of days the facility was also expected to run (about 10 days a year with average water conditions), greenhouse gas emissions from the facility were also expected to be minimal.

2.0 stakeholder meetings

2.1 PROJECT-SPECIFIC ADVISORY COMMITTEE

Representatives from the following governments and groups were invited to participate on a project-specific Advisory Committee.

- Kwanlin Dün First Nation
- Ta'an Kwäch'än Council
- Yukon Conservation Society
- neighbourhoods close to the project
- potential assessors and intervenors in the project's future regulatory process
- Yukon government's Energy Branch
- City of Whitehorse
- Yukon College
- a local economist

The Advisory Committee met three times between March and the end of June 2019. The mandate of this committee was to understand the project in-depth by way of a comprehensive presentation and discussion of the project work at key stages. Members of the committee provided us with their comments on the rationale and methodology of the project work and pointed out any errors or omissions they felt were made during the work. Committee meetings were conducted under Chatham House Rule where participants were free to use the information received, but neither the identity nor the affiliation of the speaker(s), nor that of any other participants, could be revealed.

Input from the committee is considered part of stakeholder engagement. It was not a decision body and had no role in approving work.

2.2 UPDATES AND MEETINGS WITH THE KWANLIN DÜN FIRST NATION, TA'AN KWÄCH'ÄN COUNCIL, AND INDUSTRY STAKEHOLDERS

Our senior leaders and project leads gathered input from these governments, industry groups and stakeholders through numerous meetings, phone discussions and email exchanges. These communication initiatives centred on the need for the proposed new thermal generating facility and the proposed locations and fuel type.

There were several ways for the public to provide input into this project: open houses, an online survey, household visits, social media and general email/phone calls.

Our goals were to:

- Inform stakeholders and the public about the need for the proposed new thermal generation facility
- Show where it fits into our vision of a sustainable, reliable and affordable electricity system
- Obtain feedback from the public about the preferred location and fuel type for the proposed facility
- Ensure public aspirations and concerns were consistently understood and considered

There were three types of fuel types examined:

- Liquefied natural gas (LNG)
- Diesel
- Dual-fuel (both natural gas and diesel)

There were five locations examined:

- Beside our Takhini substation
- Near the Whitehorse sewage lagoon
- At the Whitehorse landfill
- At our Whitehorse diesel plant
- Across from our LNG generating facilities

3.1 PUBLIC OPEN HOUSES

We hosted four Open Houses in Whitehorse between June 1 and June 6, 2019 to provide opportunities for members of the public to learn more about the project, ask questions and provide their input on the project.

Open House Dates and Locations:

Saturday, June 1. Canada Games Centre. 10 a.m. to 2 p.m.

Monday, June 3. NorthLight Innovation Hub. 11 a.m. to 2 p.m.

Tuesday, June 4. Grey Mountain Primary School. 6 p.m. to 9 p.m.

Thursday, June 6. Hidden Valley Elementary School. 6 p.m. to 9 p.m.

Our Open Houses were hosted in Whitehorse in order to provide residents and businesses in close proximity to the proposed locations with the opportunity to ask specific questions about the project and to provide their specific views and opinions. Ninety-four individuals attended the four open houses. Four hundred and forty-six questions and comments were received. A full report of these comments can be found in Appendix A.

3.2 HOUSEHOLD VISITS

Between May 30 and June 17, we visited approximately 175 homes and businesses within 800 metres of each of the proposed locations (in this case, only our Whitehorse diesel plant and Takhini substation options were deemed to have residents with 800 metres). We also either visited or called an additional nine businesses with operations in the broader Takhini area to get their input. We spoke to 39 individuals and businesses. In those discussions, eighteen comments about the project were received. A full report of these comments can be found in Appendix B.

3.3 ONLINE SURVEY

We recognize Yukoners are active individuals throughout the year. As a result, we worked with a professional survey developer and the Yukon Bureau of Statistics to create an online survey to enable individuals across the territory to access project information and provide input on the project at a time that best suited them. The survey was open between May 21 and June 9, 2019, and made available in both English and French. Four hundred and forty-seven survey responses were received. A full report of these survey results can be found in Appendix C.

3.4 EMAILS, LETTERS AND PHONE CALLS

To kick-off our public engagement activities, we delivered a mailer to Yukon households in mid-May 2019 with information about the proposed new thermal facility and encouraging Yukoners to learn more and provide their input. One way individuals were encouraged to provide feedback on the project was to contact our Public Engagement Team by email (communications @yec.yk.ca) or phone (867-393-5333). Sixteen emails, letter and phone calls were received between May 21 and July 15, 2019. A full report of these comments can be found in Appendix D.

3.5 SOCIAL MEDIA

We developed two 90-second videos – one detailing the location options, and one about the fuel options being considered – and utilized both paid and organic Facebook posts, and paid Google ads to share the videos with Yukoners. The purpose of the videos was to create a heightened level of awareness and interest about the project in the broader Yukon population.

Facebook and Google ads were also created and used to inform Yukoners of our project open houses and to encourage participation in the online engagement survey.

Both videos and all online ads drove people to a project-specific landing page on our website (yukonenergy.ca/thermal) where more information about the survey, open houses, proposed locations and fuel types was available. People were able to comment on the social media material developed as an additional way of providing feedback. Eighteen comments were received.

3.5 OVERVIEW SUMMARY

The table below summarizes the comments we received at the open houses, in the survey, during household and business visits, from email, letters and calls we got, and on our social media channels. Individual comments and questions may have been attributed to more than one theme depending on the context of the comment or question.

THEME	NUMBER OF COMMENTS AND QUESTIONS	SUMMARY OF COMMENTS/ QUESTIONS
Renewables and alternative solutions including demand-side management programs	**655**	» More renewables should be used instead of the continued use of fossil fuels. » Yukon Energy should consider alternates to thermal such as: Biomass Nuclear Battery storage Geothermal Pumped storage Waste heat Interconnection to Atlin, BC Garbage Solar Wind » More should be done to help people lower their demand for power and conserve energy.
Proposed location's proximity to homes and businesses	**247**	**I have concerns about:** » the project being near my home and or business » noise levels of the new plant » increased traffic » site safety » public safety » property value of my home if this is built by me » general impact on my quality of life » the project's impact on wildlife in the area
Environment / Climate Change	**177**	» The United Nations said we have 12 years to cut our GHGs by half. » The last thing the Yukon needs in a climate crisis is a discussion around new thermal capacity. » Spend the budget you have on electrical generation that doesn't contribute to climate change. » Consider pollution, emissions, air quality.

THEME	NUMBER OF COMMENTS AND QUESTIONS	SUMMARY OF COMMENTS/ QUESTIONS
Fuel Selection	**121**	» Diesel is more effective for integration of future renewables. » No fracking. No LNG. » Reliability of fuel supply chain. » Preference for fuel that starts quickly in an emergency. » Choose fuel with fewest emissions.
General questions and comments	**118**	» Are you regulated? » Water levels are low this year. » How big is your existing LNG plant? » What kind of grid-monitoring does Yukon Energy have? » What is the difference between energy and capacity? » What is an IPP? » What is better – overhead or underground power lines? » Is this really your only option? » I support this. » I don't support this.
Cost	**110**	» Impact of investment on debt cap. » Impact of project on rate payer vs. tax payer. » Lifecycle costs. » Lowest cost and impact on rates. » Highest stability of fuel pricing.
Access to site during emergencies	**94**	» Don't put all of your back-up facilities at the same site. » Not at an existing facility. A more spread out system is more robust. » Close to current facilities. » Easy to access/maintain (for Yukon Energy), safe and secure. » Proximity to existing power grid. » Access to major roads.

THEME	NUMBER OF COMMENTS AND QUESTIONS	SUMMARY OF COMMENTS/ QUESTIONS
Project Details and Context	85	» What is an emergency scenario? » How was the load forecast determined? » Are mines and/or electric vehicles considered in the load forecast? » How often will the facility be used? » How much more power is needed? » What would the footprint of the plant be? » Is the project designed to replace the temporary diesels you rent every year? » Would there be a person at this site at all times?
Renting vs owning	40	» Preference for renting instead of owning/building. » Renting is a short-term solution that does not rely on fossil fuels in the future. » Renting limits the impact of capital investment on future investments. » Deal with the risks of renting.
Engagement	15	» What is the duration and scope of public engagement? » What influence will feedback have on decisions? » What steps are being done to engage communities outside of Whitehorse? » Have First Nations been engaged?
Future Planning	13	» Build a solution that also meets future population and economic growth.
Recreation	7	» Do not remove land for residential, commercial and recreation.
Wildlife	4	» Keep disturbance for wildlife and people minimal. » Consider wildlife need and safety.
Reliability	3	» Minimize outages.
Security	2	» Security.

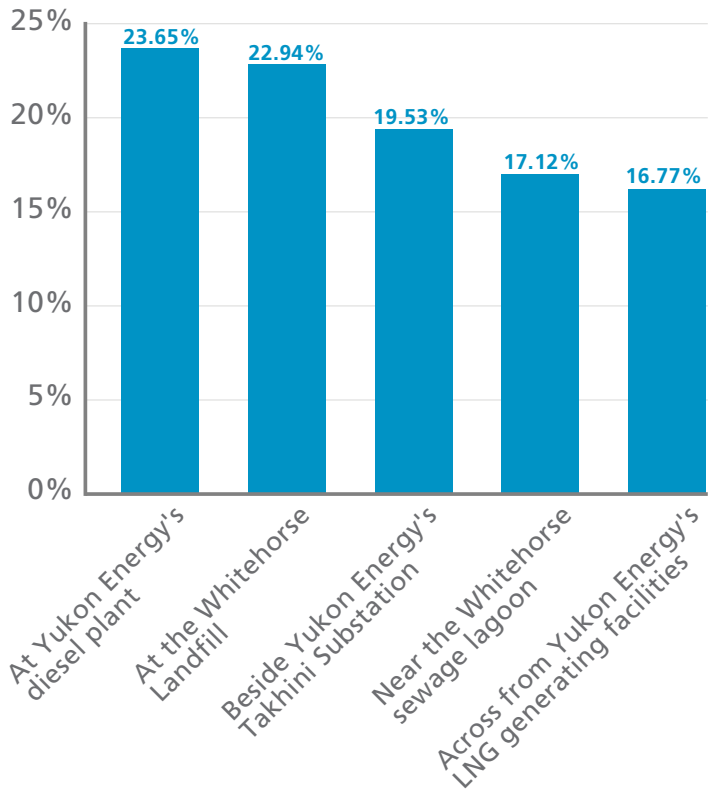
3.6 ONLINE SURVEY RESULTS

This section provides a summary of the survey results. There were 447 respondents.

Question 1

Tell us your preference for each of the following site location options for a new thermal electric generation facility.

PREFERRED LOCATION. WEIGHTED SCORE



Question 2

If you don't support any of these options, tell us why.

» Answered: 184

» Skipped: 263

Answers by theme. Please note, a single response may be attributed to one or more theme based on the comment.

THEME	RESPONSES
Renewables	90
Alternative energy solutions (e.g., biomass, nuclear, geothermal, battery)	20
Location proximity to residents (e.g., safety, noise, quality of life, property value, etc.)	18
Access to site during emergencies	15
Cost	6
Energy-conservation	6
Climate Change/Environment (including air, emissions, pollution, etc.)	5
Recreation	5
Fuel Selection	4
Wildlife	1
Other	13
No comment/can't say	13

Question 3

What is the one most important thing you would like Yukon Energy to consider regarding the location of a new thermal electricity generation facility?

» Answered: 352

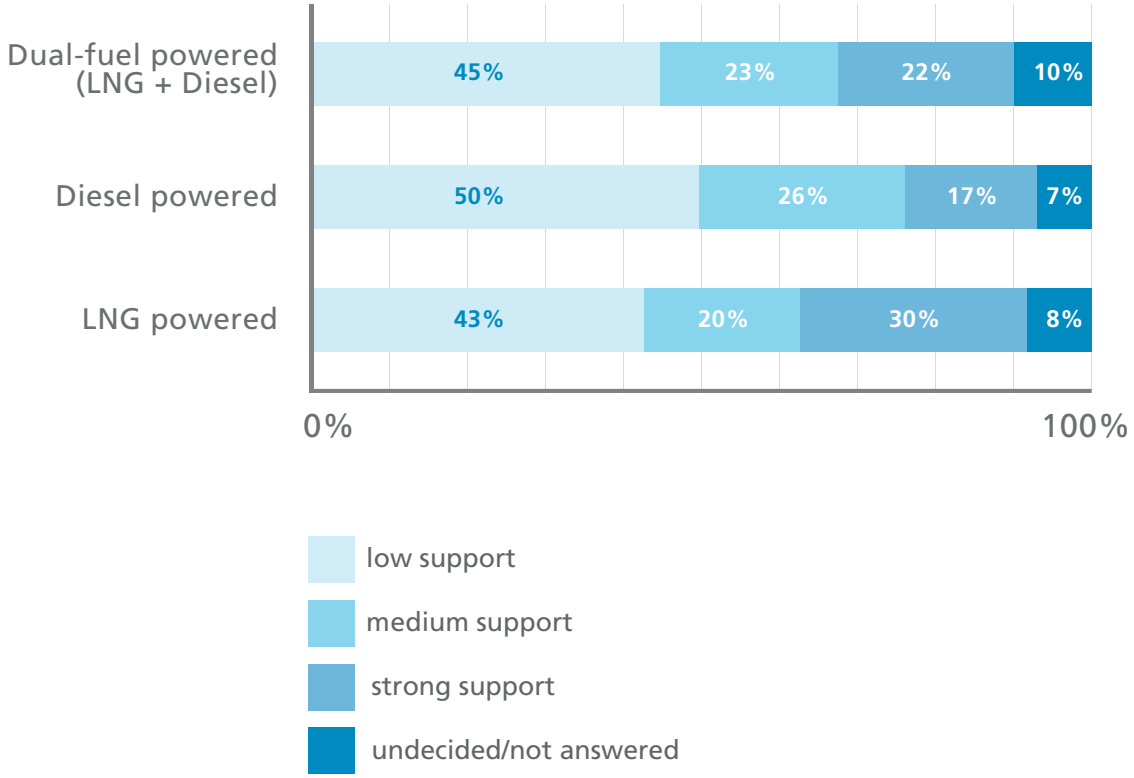
» Skipped: 95

Answers by theme. Please note, a single response may be attributed to one or more theme based on the comment.

THEME	RESPONSES
Location proximity to residents (e.g., safety, noise, quality of life, property value, etc.)	103
Access to site during emergencies	61
Renewables	60
Climate Change/Environment (including air, emissions, pollution, etc.)	51
Cost	35
Aesthetics of the site	17
Planning for future growth	13
Alternative energy solutions (e.g., biomass, nuclear, geothermal, battery)	8
Rent	8
Energy-conservation	3
Recreation	3
Service reliability	3
Security	2
Wildlife	2
Other	27
No comment	3

Question 4

Tell us your level of support for each of the following fuel generation options.



Question 5

If you didn't prefer any of these options tell us why.

» Answered: 237

» Skipped: 210

Answers by theme. Please note, a single response may be attributed to one or more theme based on the comment.

THEME	RESPONSES
Renewables	142
Alternative Energy Solutions (i.e., biomass, nuclear, geothermal)	39
Climate Change/Environment (including air, emissions, pollution, etc.)	22
Energy-conservation	12
Fracking	9
Fuel Supply	8
Cost	6
Fuel selection	6
Rent vs. own	4
Proximity to residents (including safety, noise, etc.)	3
General Comment	2
No comment/can't say	10

Question 6

What is the ONE MOST IMPORTANT thing you would like Yukon Energy to consider regarding the type of fuel to be used to power a new thermal electricity generation facility?

» Answered: 349

» Skipped: 98

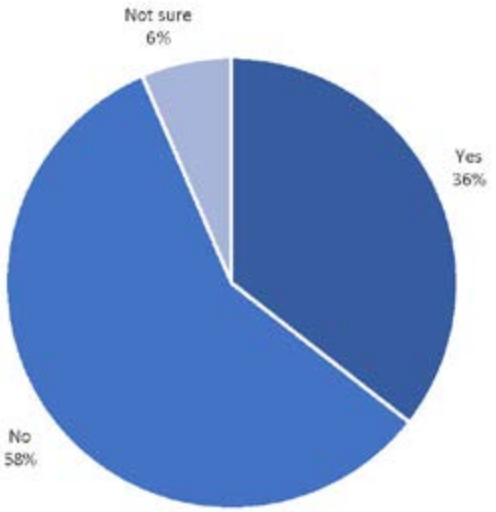
Answers by theme. Please note, a single response may be attributed to one or more theme based on the comment.

THEME	RESPONSES
Renewables	100
Climate Change/Environment (including air, emissions, pollution, etc.)	95
Cost	48
Fuel Supply	27
Service reliability	18
Fracking	18
Alternative Energy Solutions (i.e., biomass, nuclear, geothermal)	12
Proximity to residents (including safety, noise, etc.)	12
Integration of renewables	8
Rent vs. own	4
Energy-conservation	3
Jobs	3
Wildlife	1
General Comment	14
No comment/can't say	10

QUESTIONS 7 TO 16 OF THE SURVEY WERE MANDATORY AND HAD TO BE COMPLETED BY ALL RESPONDENTS TO THE SURVEY.

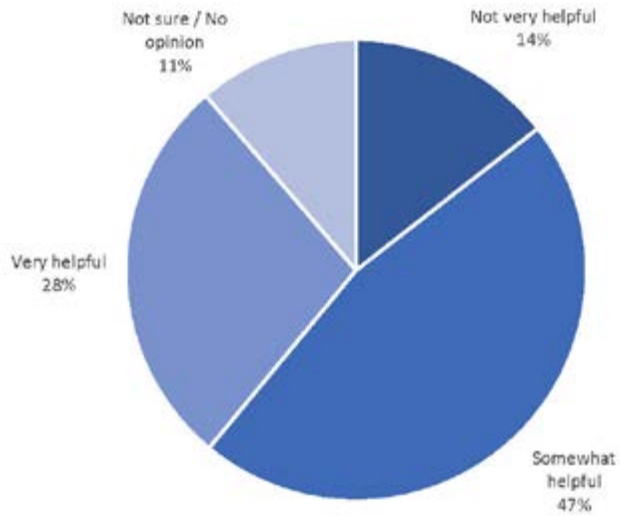
Question 7

Do you recall seeing an information brochure from Yukon Energy regarding new thermal powered electrical generation?



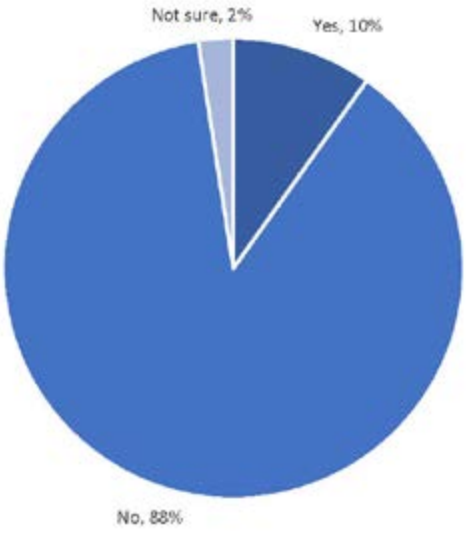
Question 8

If you recall seeing an information brochure on new thermal powered electricity generation, how helpful was it in informing you about site location and fuel source options?



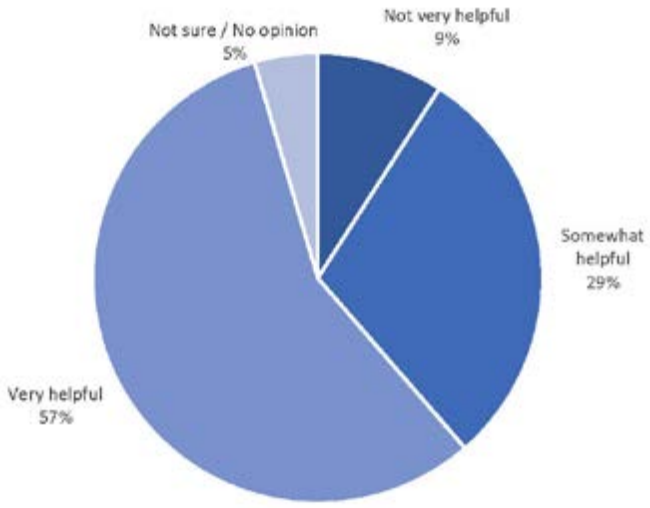
Question 9

Did you attend an Open House hosted by Yukon Energy regarding new thermal powered electrical generation?



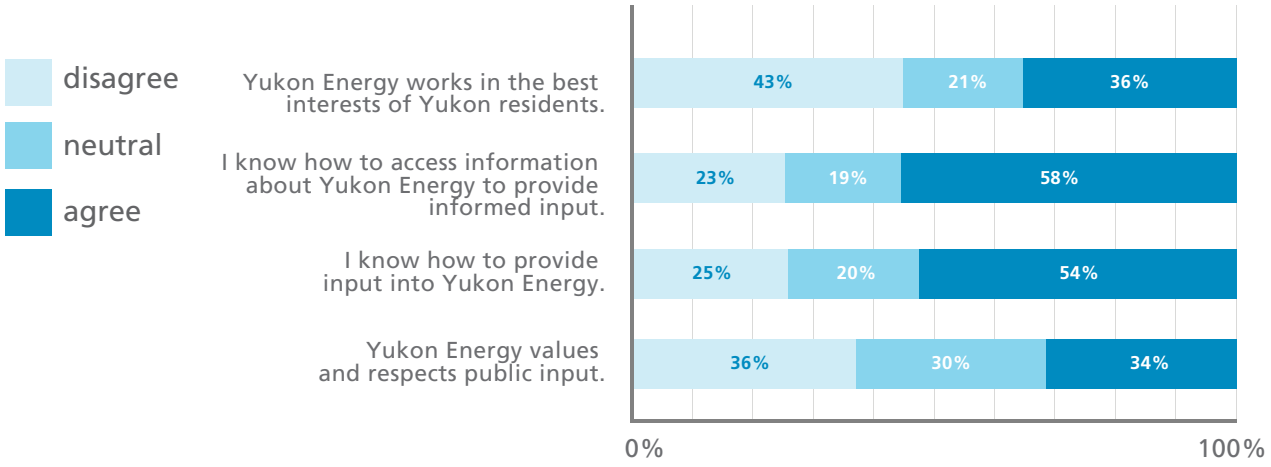
Question 10

If you attended an Open House on new thermal powered electricity generation, how helpful was it in informing you about site location and fuel source options?



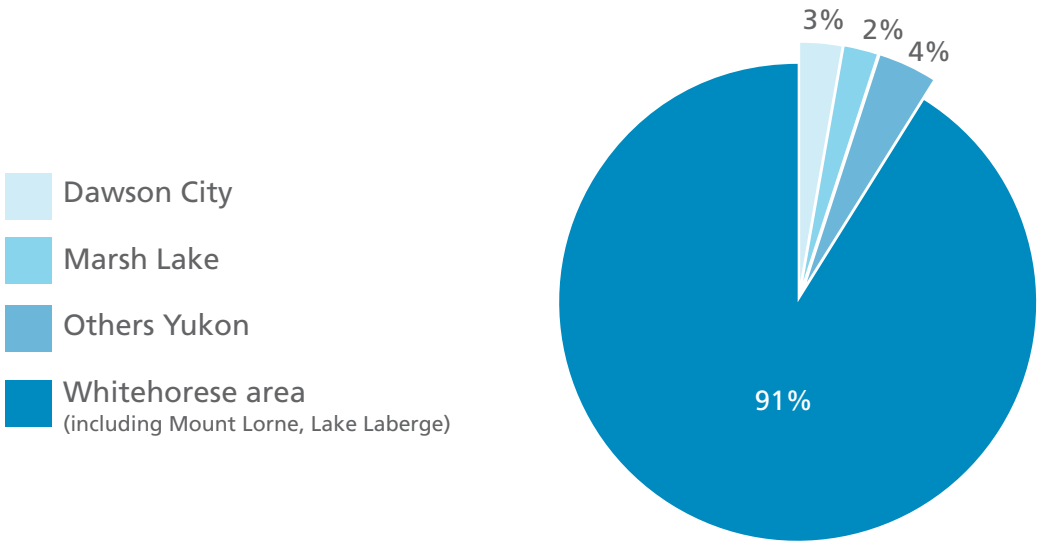
Question 11

Respondents' level of agreement with the following statements:



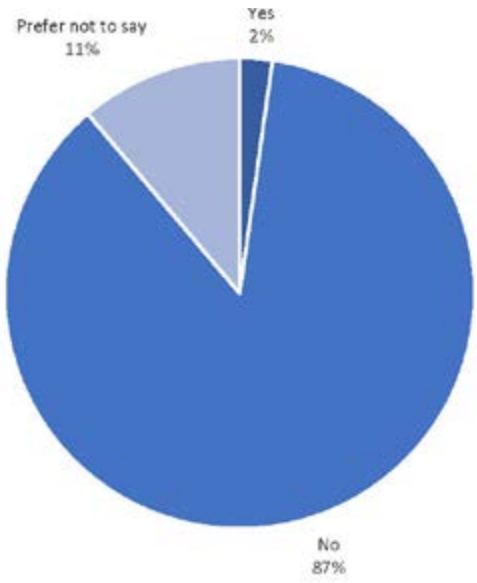
Question 12

In which community is your primary residence?



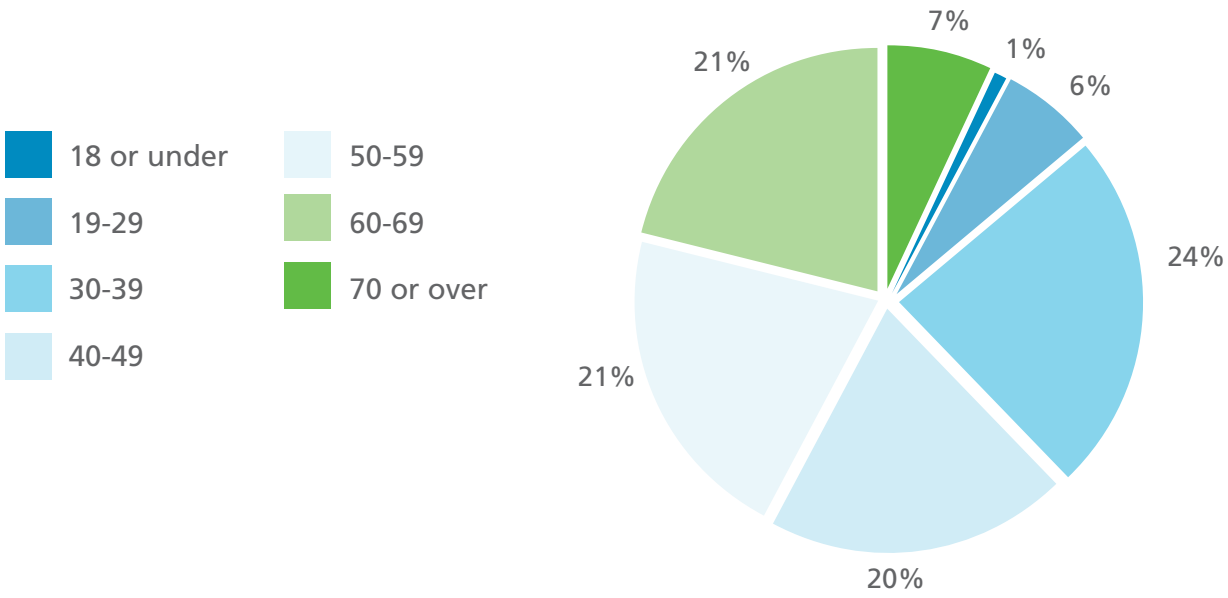
Question 13

Are you a member or citizen of a Yukon First Nation or a transboundary First Nation (British Columbia, Northwest Territories)?



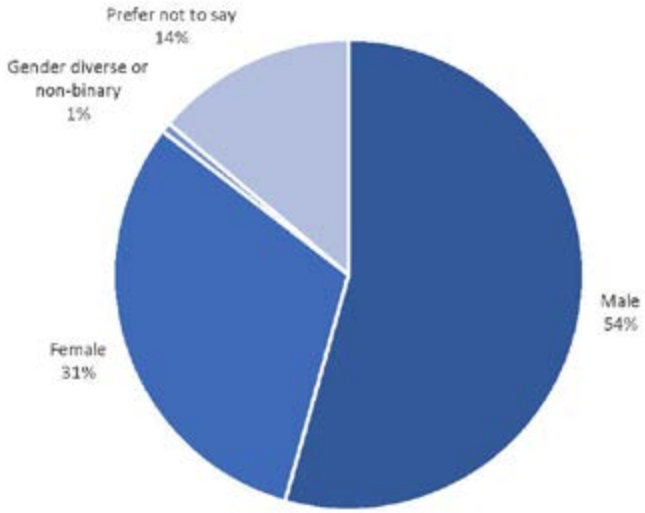
Question 14

What is your age?



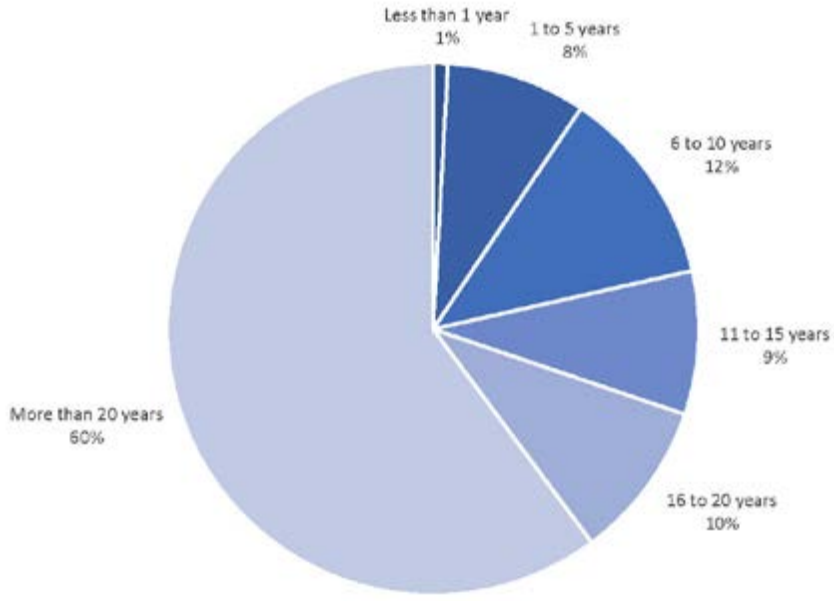
Question 15

What is your gender?



Question 16

How long have you been a Yukon resident?



4.0 summary

In order to make this information as useful as possible, we have considered all the input collected from the various engagement activities and have pulled out the key themes. They are not listed in order of importance.

1. RENEWABLES, CONSERVATION AND ALTERNATIVE SOLUTIONS

There is a strong desire for Yukon Energy to pursue renewable energy projects. Participants expressed a desire for Yukon Energy to incorporate the latest technologies (e.g. battery storage, geothermal, nuclear, biomass, wind, solar) to increase the amount of renewable power generation, and to employ new programs and technologies to allow residents to conserve and better manage their electricity use.

Participants also expressed a desire for any new renewable project to capitalize on other opportunities and needs of the territory including managing garbage and recycling, increasing employment and business ventures (i.e., secondary businesses developed to support biomass).

2. IMPACT ON RESIDENTS

Participants who attended the Open Houses cited specific concerns about the proposed facility being located near their home and asked that the facility be located in less habituated areas. Participants cited specific concerns about noise levels, increased traffic, site safety, property values and general impacts to their quality of life. Specific to the proposed Takhini location, participants stated their objection to the site given its direct conflict with 'country living' and their sense of place. Residents in Riverdale tended to be concerned with noise levels from the facility should it be located in the existing Yukon Energy Diesel Plant.

3. CLIMATE CHANGE

Participants expressed a concern about climate change and the company's proposed use of liquefied natural gas (LNG) or diesel on the environment. Participants urged Yukon Energy to explore alternatives to fossil fuels to generate electricity siting concerns about emissions, pollution, air quality and the environment in general.

4. GO GREEN, BUT IF YOU MUST, USE DIESEL

Participants urged Yukon Energy to use renewable energy sources instead of fossil fuels. But when asked specifically to choose between the use of LNG or diesel to fuel the proposed power plant, participants outlined a clear preference for diesel instead of LNG. Diesel was viewed to more effective for the integration of future renewables, while LNG was negatively viewed by many for its reliance on hydraulic fracking. A reliable fuel supply was also a consideration raised by survey respondents, which favours diesel given the established supply chain and storage facilities in Whitehorse.

5. COST

Participants sited cost as an important factor for Yukon Energy to consider when choosing the location of the facility and whether to use LNG or diesel to fuel it. Respondents encouraged Yukon Energy to select the lowest-cost option in order to limit impact of the investment on rates.

6. ACCESS DURING EMERGENCIES

When asked to choose between the five possible locations for the new power plant, respondents encouraged Yukon Energy to pick the location that could be accessed the most quickly and easily during emergencies. Respondents cited considerations such as proximity to the existing electrical grid and other back-up facilities, access to major roads, and how best to optimize operational efficiencies.

7. RENTED VS. OWNED GENERATORS

While we did not explicitly ask for public input on the preferred ownership model for the new facility, participants who commented on the topic clearly expressed a desire for Yukon Energy to rent instead of own the proposed new generators. Renting was viewed as a way for Yukon Energy to continue to meet the short-term need for dependable power, while not committing to the use of additional fossil fuel generation in the long-term. It was also viewed that the lower up-front capital costs of the rental options would make more capital available for future investments in renewable supply options.

appendix a: open houses comments and questions

June 1-6, 2019

Participant comment/question	Yukon Energy Response
Why doesn't Yukon Energy look at having all of the LNG and diesel at its existing facility rather than at different parts of town?	Certainly one of the considerations. Yukon Energy is looking at putting the new thermal generation facility at its existing diesel plant (retrofit)
What is the difference between LNG, diesel and dual-fuel?	There are three main differences: 1. LNG emits fewer greenhouse gas emissions 2. Diesel engines start up faster 3. Diesel engines respond better to changes in electricity load and are better suited to the future integration of renewables We've completed a detailed analysis between the three fuels. That information is available on a summary chart on our website, yukonenergy.ca/thermal.
Why thermal?	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs. It's important to note that this new thermal facility will not provide all of the power we need to meet the increasing demands for power in Yukon. This project is one of many we are pursuing, some of which are renewables like the development of new sources of hydroelectricity.

Can Yukon Energy control hot water tanks to manage peaks?	We are exploring that option through our pilot Residential Demand Response Program Pilot which will begin later this year
What is the difference between LNG, diesel and dual-fuel?	There are three main differences: 1. LNG emits fewer greenhouse gas emissions 2. Diesel engines start up faster 3. Diesel engines respond better to changes in electricity load and are better suited to the future integration of renewables
	We've completed a detailed analysis between the three fuels. That information is available on a summary chart on our website, yukonenergy.ca/thermal.
Drought conditions/storage	Our water license forces us to spill
The media coverage makes this project seem polarized, but now I understand the challenges.	Reinforced the need for the project.
I'm not an expert. Why do you want my opinion?	We listen to all values. Public input will be used with the research we've done on the project as input on the recommendation we put forward to our Board of Directors about the preferred location and fuel type for this project.
What is the cost of wind?	Building wind on this scale is very expensive. Wind is also not 100% dependable or dispatchable. It is also has a slower ramp up rate.
What is the cost of battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
Can the renewables in Alaska be used here?	We exploring a whole suite of renewables including hydro. Independent Power Producers will also make more renewable electricity available on the grid. We need to be mindful about the cost of being 100% renewable and what that would mean to ratepayers who will have to pay for the projects. (referred to 2016 Resource Plan)
Can the government not just pay for it, or incent it?	Referred to cost allocations in the 2016 Resource Plan (Renewables-only portfolio vs. the mixed portfolio)
Why doesn't Yukon Energy help people lower their demand for power?	We do. We offer a range of energy conservation programs.
How does the project fit into Yukon Energy's larger energy plan?	Referred to the 2016 Resource Plan and the Future-Focused portfolio panel that spoke to all of the renewable and non-renewable projects the company is working on.
What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.

What about pumped storage?	Pumped storage was explored as part of the 2016 Resource Plan. It was found to be a relatively expensive energy option compared to the competing options.
How does Yukon Energy use its waste heat from its existing LNG and diesel facilities?	In Whitehorse, we used waster heat to heat the dykes at our Whitehorse Rapids facility.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government.
What about solar and battery projects in the smaller communities?	If you store energy 50% of the time you need 200% capacity
How much power is needed in the Yukon?	Our highest recorded peak was 93 MW in 2018. 66MW of that was supplied using hydro resources. The rest was supplied with LNG and diesel.
Why do you need this facility?	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available.
Why doesn't Yukon Energy sells its waste heat to other buildings/users	Current government policy says that Yukon Energy cannot sell its waste heat to others.
Why don't we connect to Atlin, BC?	This is one project we are exploring. It would require investment from Atlin to generate the additional power we need, and an investment to build the transmission line from Atlin to the grid.
What is the cost of rentals?	Showed the participant the summary panel that outlined that rentals are more expensive than owning the LNG or diesel generators.
Yukon Energy should just invest in nuclear. It's coming.	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
The Yukon should be 100 per cent renewable.	Referred to the "renewables-only portfolio" in the 2016 Resource Plan and the cost of nearly $800 million.
Do you have any public advise as to home someone can shift their peak demand using their home heating?	We believe in energy conversation and promote it to our customers. We don't sell any products specific to home heating ourselves. We are launching a pilot program later this year where Yukoners can volunteer to have a device added

	to their hot water tank or electric baseboards to help shave and shift peak demands for electricity during the winter.
You have no option other than thermal at this time.	We agree and will be investing soon. We are obligated to serve all electricity users in the Yukon and have a duty to ensure that that power is reliable.
Growth is growth.	It all has an impact on the amount of electricity we need.
Electric cars will spike demand.	We are aware.
There should be an incentive for building green (more renewables).	Building renewables only is costly. Who would pay that extra cost? Government or ratepayers?
Building green (renewables) helps your peak.	We are proposing to build this project to help with peaks during winter months which also tend to be the coldest and darkest of days. We need dependable sources of electricity that are available year-round and in all weather conditions.
What is the worst case scenario?	We need to invest in enough back-up electricity that we can still meet the demand for power in case we were to lose generation from Aishihik (one of our largest dams).
Why doesn't Yukon Energy sells its waste heat to other buildings/users	Current government policy says that Yukon Energy cannot sell its waste heat to others.
What is it reasonable to plan for?	We are investing in our insurance plan which would allow us to still meet peak demands for power and keep the lights on in case we were to lose hydroelectricity from one of our largest dams.
Who are the biggest users?	Mines. In the case of an emergency situation we would disconnect the mines from the grid so that that power could be used by residents. The demand we are showing on this graph (Need panel), shows what demand would be without mines.
What about wind?	Building wind on this scale is very expensive. Wind is also not 100% dependable or dispatchable. It is also has a slower ramp up rate.
Is this a drought year?	Yes. We have been seeing low water levels for two years now.

Can we not use wind to reduce demand?	Wind is also not 100% dependable or dispatchable. We are planning for an emergency situation right now which means in the case we lose one of our largest hydro generating facilities or in the winter months when the peak demand is high.
Build wind.	Wind is not suitable as a backup for emergency situation as it is not 100% dependable or dispatchable in an emergency situation.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government.
What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
Looks like you need to think on the system scale	Yes, to the extent that we can.
Why not just do renewables and deal with economic consequences?	Referred to the "renewables-only portfolio" in the 2016 Resource Plan and the cost of nearly $800 million.
Your load forecast is way off	We used information available about current and projected population and economic growth, anticipated use of electric vehicles, electric heat and other variables to determine the forecasted load.
Use wind first, then use hydro as back up	Spilling is water when we already have it would be wasting valuable energy. There are also gaps in technology that don't allow wind to be the primary source of power all year round in every weather condition.
Do you plan on using 20 MW of thermal?	This is the amount that is needed for our upgraded insurance plan. We anticipate having to use this facility for about 10 days each year under normal conditions (average water, no emergencies or disasters that would destroy a hydro facility).
When the government change comes, will you even be allowed to go 100% renewable?	Referred to the "renewables-only portfolio" in the 2016 Resource Plan and the cost of nearly $800 million.

How often do you expect running this facility?	We anticipate having to use this facility for about 10 days each year under normal conditions (average water, no emergencies or disasters that would destroy a hydro facility).
The last time you added thermal it was for backup. Now it's always on.	We are in a drought, and because of that low water, we have having to use our LNG units every day to ensure there is enough power on the grid.
Your demand forecast is wrong.	We used information available about current and projected population and economic growth, anticipated use of electric vehicles, electric heat and other variables to determine the forecasted load.
I hear you saying you want thermal.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
You should use water tank monitoring and temp controls to manage peaks.	Yes, those devices can help. We are piloting a Residential Demand Response Program later this year which will help us see how much peak we can shift by remotely controlling the temperatures on hot water tanks and baseboard heat.
You sound like a broken record.	We are regulated utility with an obligation to serve and mandate to provide reliable power to individuals.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government.
What does this graph (on the why thermal panel) mean?	We are investing in our insurance plan which would allow us to still meet peak demands for power and keep the lights on in case we were to lose hydroelectricity from one of our largest dams.
Why not wind?	Wind is not suitable as a backup for emergency situation as it is not 100% dependable or dispatchable in an emergency situation.

The United Nations said we have 12 years to cut our GHGs by half.	Building renewables can take 7-10 years and costs a lot (refer to 2016 Resource Plan). We need to plan and build for an emergency situation which can happen now.
Our bills are low. Charge more. Do more.	Referred to the 2016 Resource Plan that showed that the renewable-only portfolio would cost nearly $800 million (for 99 per cent renewable), vs the mixed portfolio for $300 million for (98 per cent renewable).
What about electric cars?	We know they are coming. We accounted for a high penetration level of electric vehicles in the forecasts we developed for our 2016 Resource Plan.
What about carbon emissions?	LNG and diesel both emit carbons. Diesel more so than LNG.
Your LNG facility was supposed to be backup, but it's running all the time now.	We are in a drought, and because of that low water, we have having to use our LNG units every day to ensure there is enough power on the grid.
You used your LNG facility even before this drought too.	Yes, to meet peak demands for electricity that couldn't be met using hydro alone, and for days we had to do maintenance on the hydro or LNG units.
You should have stored the water when you had the chance.	Our regulations say that we can store water based on the parameters that are outlined in each of our Water Use Licenses.
Build more renewables please.	We are committed to renewables too. More than 90% of the electricity we generate is renewable already. Money is limited and to be 100 per cent renewable would cost a lot more than having a mix portfolio (referred to 2016 Resource Plan).
Do you really care about our opinions?	Yes. We want to hear all perspectives. Your feedback will be used with the research we've done on the project as input on the recommendation we put forward to our Board of Directors about the preferred location and fuel type for this project.
I'm tired of years of Yukon Energy not listening.	We are trying. Plans to build renewables don't always work out.
Why don't you connect to Atlin hydro?	We're looking into it. It would require investment from Atlin to generate the additional power we need, and an investment

	to build the transmission line from Atlin to the grid.
Build solar everywhere on government money.	Solar is not an optimal solution to provide winter back-up. That's why we're here today. To speak about the LNG and diesel that we need in case of an emergency and when peaks demands for power are at their highest (usually in the winter)
Sign us up for the water heater pilot project.	More information about our Residential Demand Response Program will be coming out this fall.
You appear to be embracing gas.	We use LNG and diesel now. No decision has been made about whether this new facility will be LNG or diesel.
Does the Government have a stance?	Yes, like us they would like to see more renewables come online.
Does the load you show include mines?	No (refer to Why thermal? panel)
Water levels are low this year.	Yes they have been for a couple of years now.
Are you regulated?	Yes, by the Yukon Utilities Board. Our projects must also be approved by YESAB.
Thermal is your short term plan. Do you have a long term?	Yes. This new thermal facility is just one of the projects we're working on in our new future-focused portfolio. Referred to future-focused portfolio panel (spoke about new hydro, upgraded hydro, storage enhancements and battery).
Hydro is best.	We must look at what's needed to provide reliable and affordable power in the short, medium and long term.
I guess building renewables depends on who owns the land. Many can say no.	Yes, it can be difficult to build renewables if individuals or communities do not want it nearby.
Build more renewables	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.

How far is the proposed site in Takhini from the highway?	Showed participant the Midgard map for the proposed site (available in hard copy and online).
People should install and sell the solar back to the grid.	Customers can do that through the government's Microgeneration policy. Independent Power Producers can do it through the government IPP policy.
Is small hydro doable?	Yes. We assessed a number of locations during our 2016 Resource Plan and are exploring the options to build small hydro in Drury Creek and to connect to Atlin.
Is it possible to build hydro in Dawson?	To generate hydroelectricity you need a large change in elevations. Dawson is wide and slow.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
What are your long term plans?	When we did our 2016 Resource Plan we looked a variety of possible projects to help us meet future demand – a new thermal facility was just one of them. In addition to this project we're working on a portfolio of other projects including: • upgrades to our existing hydro facilities; • hydro storage enhancements; • building new hydro, and • installing a grid-sized battery.
Is an LNG depot being built in Whitehorse?	We are aware that a third-party vendor is exploring that option. The LNG depot is not a Yukon Energy project and out of our control.
The value of my home will drop if the facility is built by me.	Many factors are considered when assessing the value of a property.
Takhini has no real fire response.	Thank you for informing us of this. We are in the early stages of this project. Should the Takhini site be deemed to be the preferred location for the new facility we will certainly take this into consideration and adjust our plans accordingly.
Traffic on the highway beside the proposed Takhini site is fast. Having trucks turning here could be a possible safety issue.	Thank you for the feedback. We will include this as part of our assessment of the site.
What about the noise, smell, and health effects from fumes?	We anticipate running this facility for about 10 days each year under normal/average conditions (not low water or no emergency).

	We've done preliminary air quality studies and they've shown that there is no foreseeable significant impacts of emissions from the facility to nearby residents. Take our existing diesel and LNG facility for example. Our new facility will be no closer to residents as the existing facilities are to residents in Riverdale and these facilities have passed previous air quality and human health impact assessments. If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
5Mile road is a dead end in case of fire.	Thank you for the feedback. We will include this as part of our assessment of the site.
I would rather have no power for two days then have this near homes.	Yukon Energy is committed to providing reliable power to our customers. This project is needed in case of an emergency, to help meet peak demands for power and when other renewables aren't available. We anticipate only using the facility for about 10 days a year during normal conditions (average water/no emergencies).
Will you announce the location?	Yes. We will be providing letting Yukoners know the decision we made and how feedback and research influenced that decision.
I don't want to have this by my house.	Thank you for the feedback. We will include this as part of our assessment of the site.
The road beside the proposed Takhini site is used for races.	Thank you for the feedback. We will include this as part of our assessment of the site.
The area beside the Takhini site is a wildlife corridor.	Thank you for the feedback. We will include this as part of our assessment of the site.

Building at the sewage lagoon would be a good reason to build a second bridge to Riverdale.	Those types of decisions are made by the City of Whitehorse.
It sounds silly to have all of your back-up plants in one locations (referring to proposed Diesel site).	Thank you for the feedback. We will include this as part of our assessment of the site.
You should replace all of the diesels in Whitehorse.	Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to generate power during emergency situations.
The cost to rent or buy isn't that different. Rent the new generators instead of buying them so we can get rid of them in 15 -20 years.	Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset. By investing in an owned solution we can ensure that this additional power is always available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government.
There are quarry out in the Takhini area. By building this plant here we will have homes surrounded by industry.	The proposed Takhini site is just one of five locations we are looking at. (referred to location panels and maps).
In the case of an emergency beside the Takhini site, you could be blocking off south access to the Highway.	Thank you for the feedback. We will include this as part of our assessment of the site.
My property value would drop if your build this beside me.	Many factors are considered when assessing the value of a property.
In case of an explosion what would the radius be of those affected?	We can't say for sure, but I can say that the risk of an explosion is very small.
How loud would the facility be?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way.

	If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
What about biomass?	This project is needed to provide power in the case of an emergency, to help meet peak demands for power and when other renewables aren't available. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
Renting is the only good idea so that we are not tied to it	Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset. By investing in an owned solution we can ensure that this additional power is always available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service.
Deal with the risks of renting, it's not like all of the rental generators will fail or be in poor condition.	The condition and quality of the rentals is only one concern. The other is the uncertainty about how much future rentals will cost and uncertainty about if enough would be available each year for what we need.
What about pump storage?	Pumped storage was explored in the 2016 Resource Plan. It is a relatively expensive energy option compared to the competing options
Is distance from residence considered a pro or con in your evaluation?	It is a consideration we will look at to determine a preferred location for the project.

How loud will the generators be?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
The government made a commitment not to frack in the Yukon so I don't want to see fracking elsewhere.	Diesel is another fuel option we are exploring for this project.
I didn't realize this project was for back-up only.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
Yukon Government will need to change their passive stance on renewables.	Yukon Energy, like the Yukon Government is committed to renewables.
Before these generators are decommissioned, there will be a better way to address this need.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
I want to see us rent these units. Buying them is a deal-breaker for me.	Thank you for the feedback. We will include this as part of our assessment of the site.
The Lagoon option is too far; the Landfill site looks good.	Thank you for the feedback. We will include this as part of our assessment of the site.
I don't want to see the use of LNG.	Diesel is another fuel option we are exploring for this project.

	uncertainty about if enough would be available each year for what we need.
What about pump storage?	Pumped storage was explored in the 2016 Resource Plan. It is a relatively expensive energy option compared to the competing options
Is distance from residence considered a pro or con in your evaluation?	It is a consideration we will look at to determine a preferred location for the project.
How loud will the generators be?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
The government made a commitment not to frack in the Yukon so I don't want to see fracking elsewhere.	Diesel is another fuel option we are exploring for this project.
I didn't realize this project was for back-up only.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
Yukon Government will need to change their passive stance on renewables.	Yukon Energy, like the Yukon Government is committed to renewables.
Before these generators are decommissioned, there will be a better way to address this need.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using

	LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
I want to see us rent these units. Buying them is a deal-breaker for me.	Thank you for the feedback. We will include this as part of our assessment of the site.
The Lagoon option is too far; the Landfill site looks good.	Thank you for the feedback. We will include this as part of our assessment of the site.
I don't want to see the use of LNG.	Diesel is another fuel option we are exploring for this project.
Why aren't renewables coming in faster?	We continue to work on hydro developments but like other renewables, these projects take time to find a suitable location, get social license to build there and to obtain permits and the funding.
Why does LNG take so long to heat up?	It takes LNG engines longer to warm up when compared to diesel engines.
How much capacity is Aishihik?	37MW
I read a report that says that Yukon Energy supports LNG over Diesel.	LNG has fewer emissions than diesel units but we don't have a preference in terms of one fuel over the other. There are operational benefits to both.
What is Yukon Energy doing to try to shift peak loads to different times of the day?	We are piloting a Residential Demand Response Program later this year which will help us see how much peak we can shift by remotely controlling the temperatures on hot water tanks and baseboard heat.
Have you looked at using a turbine for instream?	Fairbanks has done a lot of tests. Capacity is good in summer only
Where would the location of #4 (the diesel plant) be?	In the existing diesel plant at the Yukon Energy office on Robert Service Way. It would be a retrofit of the existing building.
Is Yukon Energy profitable?	According to the Yukon Utilities Board we are allowed to earn a rate of return on our investments. Historically, that rate has been between five and seven per cent.

How you assessed the cost of each of the portfolios?	A variety of renewable options were explored as part of our 2016 Resource Plan. Costs for each are available in the detailed plan available online at yukonenergy.ca
How long are peaks?	Usually between 10 and 15 minutes depending on the temperatures outside.
How much will this new facility be used?	We anticipate having to use this facility for about 10 days each year under normal conditions (average water, no emergencies or disasters that would destroy a hydro facility).
What about small nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
What is the cost of a battery?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
How did Yukon Energy choose these sites?	We took into account and weighed a number of different factors including: 1. Distance to the existing electrical grid. We wanted a location close the existing transmission lines to limit cost and disturbance footprint to connect the facility to the grid. 2. Opportunities for First Nation partnerships or investment. We wanted to explore locations that could potentially include a First Nation partner in the project. 3. Impacts to land development (Brownfield vs. Greenfield). We wanted to explore options where other industrial activity already exists or is nearby to limit disturbance of new areas. 4. Land conditions. We needed to look at locations where the ground conditions were suitable for this type of construction.
Is there a power line near the Lagoon	Yes, a 138 kV transmission line. Referred participant to the hard copy maps of the locations (also available online).

Are there any favorites?	No. At this point we are exploring the technical, social, economic and environmental considerations of each options as well as collecting public feedback on each proposed site.
Are there any possible non fossil fuel ideas for back up?	For what this project is needed for (emergencies, low water, peak demands), not yet. We need a resource that is 100 per cent dependable and dispatchable meaning that it can be switched on at a moment's notice.
What is the longest blackout you experienced?	On an isolated grid like ours, black outs are not acceptable.
How are you going to upgrade the dam?	We are currently working on projects to maximize the amount of power we can generate with the assets we have and looking at increasing the storage or more water in summer and fall months for use in the winter.
What is peak energy?	It's that highest amount of electricity that everyone needs at a single point in time. It is usually seasonal (happening in the winter), and happens usually when everyone gets home from work (around dinner time), and in the morning (as people are getting ready for work and school).
What about a battery?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
What can you do with the 1.7 billion?	We don't have access to that level of money so we haven't explored those options.
Do you anticipate that fossil fuels will be phased out in 40 years?	On an isolated grid like ours, there will always be a need for some kind of thermal back-up for emergencies and when renewables aren't available.
I want you to rent these generators instead of buy them.	Thank you for the feedback. We will include this as part of our assessment of the project.

With how much louder will this new facility be?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
How many delivery trucks are going to your LNG facility today?	A couple a day.
What is the capacity of those trucks?	80,000lbs.
The area around the diesel facility is a recreational area, but you say there will be no impact.	The diesel facility options would be a retrofit of the existing building, not the construction of a new site.
Why do you only rent diesels in the winter months?	Right now, we don't need them in summer.
Has the First Nation provided input into the site across the LNG facility?	Yes, we have been discussing this option with them.
Will are there concerns about LNG supply?	No. We store some LNG in our existing LNG facility.
Would you consider our energy demand to be high?	Not compared to BC or other provinces.
Have you surveyed the Landfill location yet?	No. Survey of the site would happen if we determined to proceed with that site as the preferred option.
Where is the existing transmission line beside the Landfill?	Behind it. Referred to the site map (hard copy, also available online).
How do you collect community input	Right here by having open houses like this. We are also hosting an online survey so that people who can't attend the open house can also provide their input. People can also email or call our office.

The Hot Springs is going to grow in 2020, 2021. Have you explored geothermal there?	Geothermal was assessed as an option in our 2016 Resource Plan, but was found to be too expensive to be included in the most cost-effective portfolio we are pursuing now.
Don't we use LNG already?	Yes, however replaced the old diesels we had that had to be retired. Based on forecasted demand, we need more LNG or diesel to meet demand for power during emergencies, peaks and when renewables are not available.
I don't care what fuel is used. Location is the big deal for me. I don't want it by me or other residents.	Thank you for the feedback. We will include this as part of our assessment of the project.
What about noise?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
What is the difference between LNG and diesel?	There are three main differences: 1. LNG emits fewer greenhouse gas emissions 2. Diesel engines start up faster 3. Diesel engines respond better to changes in electricity load and are better suited to the future integration of renewables We've completed a detailed analysis between the three fuels. That information is available on a summary chart on our website, yukonenergy.ca/thermal.
Is diesel cleaner than LNG?	Diesel emits more emissions than LNG.

Why not have smart meters?	ATCO previously submitted an application to the Yukon Utilities Board to do a smart meter pilot and it was denied.
The government is supporting electric cars.	The use of electric vehicles was considered in our demand forecasts (show the need diagram).
What about biomass?	This project is needed to provide power in the case of an emergency, to help meet peak demands for power and when other renewables aren't available. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
What about using garbage to generate power?	This can be considered a form of biomass product. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
What is the capacity of the LNG plant you already have?	12.8 MW
Why is LNG higher?	The upfront capital cost to build a LNG facility is more expensive than a diesel facility.
What is thermal generation?	Liquefied natural gas (LNG), diesel or dual fuel.
What is dual fuel?	Runs on both diesel and LNG. Starts on diesel, runs on LNG.
What other options have you looked at for emergencies?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.

What would like facility be used as back-up for?	In case we were to lose our largest hydro facility (Aishihik at 37 MW), as well as emergencies, low water and when peak demands are high.
Would this facility run all the time?	We anticipate having to use this facility for about 10 days each year under normal conditions (average water, no emergencies or disasters that would destroy a hydro facility).
What about noise?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
There are five site you are looking at. How many would you build?	Just one.
Would this provide back-up to mines?	Mines have their own back-up which they pay for themselves. We didn't include mines in our forecast of demand that we need to meet in case of any emergency.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
What is the purpose of this project?	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice.
Would you build in all five places?	No. Just one.

Who is looking at building the LNG depot?	Ferus
Is Yukon Energy locked into using fossil fuels	No, we are working a portfolio of renewable and non-renewable projects that are needed to meet the increasing demand for electricity in Yukon. It includes this project, new hydro, upgrade and storage enhancements to existing hydro and a grid-scale battery.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
Is Yukon Energy Corporation going to suppress information again	All information that was is used to help us inform the decisions we make about this project will be made available as part of our application processes to YESAB and the YUB.
What about Moon Lake?	Moon Lake BC is too far and too expensive for us to connect to.
What about geothermal in Watson Lake?	Geothermal was assessed as an option in our 2016 Resource Plan, but was found to be too expensive to be included in the most cost-effective portfolio we are pursuing now.
There is too much fossil fuel. I want to see more renewables.	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs. It's important to note that this new thermal facility will not provide all of the power we need to meet the increasing demands for power in Yukon. This project is one of many we are pursuing, some of which are renewables like the development of new sources of hydroelectricity.
What is the life span of hydro dam?	Hydro dams can have a life of anywhere between 50 and 100 years. Each of our hydro dams will eventually major refurbishments.

What about connect Skagway to Yukon?	It would be too costly.
What is better? Overhead or underground power lines?	Overhead power lines are much more affordable to build, and easier to maintain, repair and/or upgrade because you can visually inspect them. Underground power lines are less exposed to the elements.
When would you use AC (alternate current) vs DC (direct current)?	Direct current is most commonly used to transmit power over long distances (hundreds of km).
What is the capacity of new plant?	20MW
What other hydro options are you exploring?	We explored many different options during our 2016 Resource Plan. We are currently exploring two options in more details: Drury Creek and Atlin.
Make energy more expensive so people have to choose to use it wisely.	We do offer a number of energy conservation programs. We are also going to pilot a Residential Demand Response program last this year to see if, with the public's help, we can shift peak demands.
Hydro water supply has been decreasing. Is this the new norm?	Climate change research suggests that weather will become wetter over time, but wet dry long term cycles still occur like the drought period we are experiencing now.
Is it beneficial to use wind in Yukon	There is a place for wind in the renewable mix, especially when it comes to renewables developed by Independent Power Producers. For this project we are looking for dependable dispatchable power that is available all year round in any weather. That is why we are looking at LNG and diesel.
Why don't we connect to BC?	The Yukon Government explored this option and it was deemed to be too expensive.
What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most

	cost-effective portfolio of resources needed to meet the increased demands for electricity.
How much LNG and diesel does Yukon Energy use now?	We track this on our website (yukonenergy.ca). Keep in mind, we're currently in a year with low water so we are using more LNG now than similar times of the year in years past.
What about using geothermal as base load?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
Is there any advantage to placing this facility further away outside of town?	Each site has site specific considerations that need to be considered as part of the decision.
Do you expect more mines in the future?	Yes, and mines do add significant load to the grid, however for this project, we accounted for that and are basis are need for more power on electricity demand without mines.
When will this project be completed?	If approved, we plan to have this plant built in 3.5 years.
Are you looking at renting or owning the generators?	Both options are being considered.
Why does LNG have a slower start up rate?	It takes time to convert the LNG into natural gas first.
What is the start-up time of LNG?	15 minutes in the winter.
Are we in a low water year?	Yes, we have seen lower than average snow packs in all three of our hydro reservoirs.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for

	backup and to help levelize peak demands for power.
I would prefer the diesel location.	Thank you for the feedback. We will include this as part of our assessment of the project.
Why are mines not included in your emergency plan (the demand line of the need panel)?	In the case of an emergency we would disconnect mines from the grid so that that power could be used for other customers.
Is LNG less expensive?	LNG fuel is more affordable than diesel, however building a LNG plant is more expensive that a diesel facility.
What socio-economic considerations have been made about each site?	We looked at a variety of social, economic, financial, environmental and technical considerations. Let me show you how they are summarized by site (showed panels with considerations listed).
It seems unfair that fuel cost analysis includes the capital cost of building the fuel plant	We looked at the 40-year life-cycle cost to build, operate and maintain each type of plant for each fuel source.
Can this plant be used as base load if needed?	That is not the intention of this project, but yes, if needed, we could run this plant for base load.
How large is the plant?	LNG – about 3 football fields Diesel – about 2 football fields Dual-Fuel – about 1.5 football fields in the existing diesel plant building
How does duel fuel work?	It uses diesel to start up and then operates using LNG (about 70% LNG/ 30% diesel)
Does dual-fuel cost more?	A little more than diesel, but is certainly is more useful to use both fuels (lower emissions running on LNG, protects against fuel cost variability and secures supply).
What does supply loss of Aishihik mean?	It means a scenario where we lost about 37 MW of hydroelectricity because the transmission line between Aishihik and Whitehorse went down or had an equipment failure, or there was a failure at the Aishihik generation facility which meant no hydro power could be generated there.

What are the two possible hydro projects?	Atlin and Drury Creek
Have you considered an IPP for this project?	This type of facility wouldn't likely be economical for an IPP as it is only meant to run for about 10 days a year when there is an emergency, low water, to help meet peak demands and when renewables aren't available.
What is an IPP?	Independent Power Producer. Acts like a small utility that builds renewable projects and sells the power they generate to Yukon Energy or ATCO for use on the grid.
What about battery storage?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
What is the Mayo storage enhancement?	We are exploring being able to store more water in our Mayo reservoirs during fall for use in winter.
I would rather see Yukon Energy Corporation go full renewables.	As an isolated grid there will always be a need for some thermal power generation for emergencies. As part of our 2016 Resource Plan, we explored what it would take to be 99 per cent renewable; it would cost $785 million. Being 88% renewable which is the portfolio we're working towards now would only cost $300 million.
I'd rather see you rent than buy the generators.	Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset. By investing in an owned solution we can ensure that this additional power is always

	available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service.
We should be doing more to encourage energy conservation.	Energy vs capacity. LNG was originally peaking now it's used for capacity
Wasn't your LNG plant only meant to be for back-up? Now it seems to be running all the time.	Our LNG facilities were installed to replace diesel generators that had reached their end of life. They were mean to be used as back-up, but with the low water levels we are experiencing this year, we are needing to use them to supply the electricity we cannot generate with hydro.
What is the amount of energy available each year?	Referred to the 2016 Resource Plan summary with the energy and capacity charts.
Why not have a renewable energy target?	As part of our 2016 resource plan we assessed the amount of power we would need in terms of energy and capacity and a full range of renewables projects that would help meet those needs. We are working to bring the most cost-effective suite of products (that still meets our needs) forward.
How does debt cap get affected by a project of this nature?	We do not intend to ask Yukon Government to contribute to the cost of this project.
When does your survey close?	June 9th
Why does Yukon Energy not have a policy for renewables?	We don't set policy for energy development. That would be a role for the Yukon Government.
I believe there is a resident 1 km away from the proposed location at the Lagoon.	Thanks for the information.
Is the noise very disturbing?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner.

	Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
What renewables is Yukon Energy exploring going forward?	We are currently exploring two small hydro developments: one in Drury Creek and one in Atlin. We're also upgrading our existing hydro facilities, and looking and enhancement storage at the Whitehorse and mayo reservoirs.
What are the power generators Yukon Energy has around Whitehorse?	Showed the need map graph that showed the different dependent sources of power generation and explained the addition of Aishihik.
Given the slower start-up rate of LNG, is using diesel better?	Diesel does start-up quicker, and is cheaper to build, operate and maintain over 40 years. LNG has fewer emissions.
How long before this new plant would be operational?	About 3.5 years.
Is it certain that you are moving forward with this project or other options being explored?	The need for this project was identified in our 2016 Resource Plan to address the capacity gap we are facing because of an increasing demand for power. This is one of many projects we are working on as part of our portfolio of renewable and thermal projects.
Is this project designed to replace the temporary diesels you rent every year?	Yes.
When would you run these or the rental diesels?	During emergencies or to help us meet winter peak demands for power and when renewables aren't available.
What is the cost comparison for this project over 20 years?	As part of our analysis we looked at the cost to build, operate and maintain each of the proposed fuels at each of the proposed sites over 40 years.
We might not need these for 40 years.	40 years is the typical life of these types of assets so that is why we choose that lifecycle to assess costs over.

Are you considering the impact of electric cars?	Yes. As part of our 2016 Resource Plan and the electric demand we forecast, we did include a penetration of electric vehicles.
Wind only takes two years to install.	Yes, the installation of wind can be quick, however, wind is not considered to be a dependable and dispatchable renewable that can be relied on all year round in all weather conditions. That's what this LNG and diesel plant are looking to address.
Why not install enough wind and solar, and make hydro back-up for wind?	That would require a lot of wind. As mentioned, wind is also not a reliable source of power year round and in all weather conditions. That's why we are exploring this LNG or diesel facility.
Takhini shows natural gas. Why?	There has been some discussion from a third-party vendor that they are looking at building a LNG depot in that area. Knowing that, we thought it would be prudent to include an option to use that natural gas to fuel this plan should that deport be built.
What about summer peaks?	We typically store enough hydro to address those peaks.
Have you gotten to this point after considering all your options?	This project stems from the research we did during our 2016 Resource Plan which showed that we need more dependable power generation to meet current and forecasted demands for power.
How desperate are you to meet these loads?	We need to have a secure reliable supply of electricity. During the winter there are times that we are running almost everything we have to meet peak demands for power.
What do you expect to get from the public?	We want to get input from the public on their views about the preferred location and fuel to be used for this project. The feedback will be used with research to provide a recommendation to our Board.
Will this asset assist with providing power when extreme weather occurs?	Yes.
How would this project affect rates?	Like nearly everything we do and costs we incur, we would apply to have these costs

	included in the rates we recover from customers over the life of the project.
Will this increase reliability with respect to vulnerable population, elders, and kids?	Yes. This asset will be able to be used during emergencies, to help meet peak demands for power and when renewables aren't available.
Is the site across from the LNG facility higher than the water level at Schwatka?	Yes, I believe so.
Is Yukon Energy looking at more hydro developments?	Yes. Our 2016 Resource Plan explored many options. Two that seemed the most feasible that we are exploring right now are Drury Creek and Atlin.
What is the life space of the facility?	We're looking at a 40-year forecast.
What is the purpose of this plant?	We need this facility during emergencies, to meet peak demands for power, and when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs.
What is the life-cycle cost of the other options you explored?	All of the reports and research we conducted as part of our 2016 Resource Plan is on our website.
With electrical loads increasing, why look at a more permanent solution?	We are working on a whole portfolio or renewable and thermal projects to ensure we can continue to meet demand and have enough electricity. This project is specifically designed to help us during emergencies, during peaks and when renewables are not available.
Any investments in hydroelectric is beneficial.	Yes. Right now, we are looking for dependable and dispatchable source of power that will be used during emergencies, during peaks and when renewables are not available.
Who are Yukon Energy's main customers?	ATCO (wholesales), mines, and residents/business in Mayo, Dawson, Faro and a number of other communities.

Could you run this plant as an alternative to Whitehorse LNG?	Yes.
How big is your existing LNG facility?	13.2 MW.
Would there be person at these sites all the time?	No, only when we need to run them.
I like the Takhini and Sewage Lagoon sites but those roads are remote.	Thank you for the feedback. We will include this as part of our assessment of the project.
Closest people to Takhini sub is 300 meters and a driveway is right next to it.	Thank you for the feedback. We will include this as part of our assessment of the project.
What is the timeline for construction?	About 3.5 years.
What would be the footprint of the plant?	LNG – about 3 football fields Diesel – about 2 football fields Dual-Fuel – about 1.5 football fields in the existing diesel plant building
There are country residential lots right next to Takhini sub	Thank you for the feedback. We will include this as part of our assessment of the project.
Was carbon tax included in the assessment?	No. Legislation about carbon tax is not finalized in Yukon so it was not included.
Wad carbon tax considered?	No. Legislation about carbon tax is not finalized in Yukon so it was not included.
Would your existing LNG plant or this one run first?	Existing LNG, then this one if needed.
Would biomass be considered?	This project is needed to provide power in the case of an emergency, to help meet peak demands for power and when other renewables aren't available. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
Why is the own option at Takhini so much less than the others?	Because that site is outside of Whitehorse City limits we would not need to pay city property taxes on it.
Are you looking to build at all five or just one site?	Just one.
Did you account for the total lifecycle cost of carbon in your analysis?	Yes.

What about using biomass at the landfill location?	This project is needed to provide power in the case of an emergency, to help meet peak demands for power and when other renewables aren't available. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
What is the definition of thermal?	LNG and diesel are considered thermal, however, geothermal is not.
Is this project for the support of mining activity?	This is not geared to supporting mines, in the event of an emergency the mines power will be shut off to meet the grid demand.
Is there a hydro plant in Faro or Mayo?	There are hydro plants in Mayo, Whitehorse and Aishihik, not Faro. The Mayo hydro facility was built for the Elsa mine. Once the mine closed the Mayo-Dawson transmission line was built. Water levels are very low this year and Yukon Government has indicated Yukon is in a draught with Carmacks being the epicentre. The last draught was in 1996-1999, at that time we had surplus energy to compensate however that is not the case right now.
Why is it a thermal project and not renewable and why has it taken so long?	We will still be at 90% renewable. This project is for emergencies, such as the loss of a hydro unit as we are on an isolated grid. We are also working on a portfolio of renewable and non-renewable projects that are needed to meet the increasing demand for electricity in Yukon. It includes this project, new hydro, upgrade and storage enhancements to existing hydro and a grid-scale battery.
Why are we not connecting to the BC grid?	It is not cost effective and the line loss is very high over such a long distance. Currently we are upgrading hydro projects, enhancing storage capabilities and exploring new hydro and battery storage for renewable resources.
Why not dual fuel?	Dual fuel is one option we are exploring at the proposed diesel plant location.

How long will the LNG supply last?	Right now estimated at +100 years. The current supply is large and LNG is the cleanest fossil fuel.
Is Yukon Energy doing anything geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
How much fuel would the new LNG tanks hold?	Enough to run for one day.
I prefer the diesel site and retrofit the diesel building. The Sewage lagoon least preferable.	Thank you for the feedback. We will include this as part of our assessment of the project.
What about battery?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
How efficient are inverters?	Battery storage would allow us to be very efficient when using LNG, diesel and hydro. We would use the battery to provide backup and allow us to switch from one load to another. The proposed Lithium Ion batteries have a life of 10,000 cycles. Flow batteries have a capacity to be long term.
What happens when an LNG accident occurs?	LNG evaporates, it does not affect the land. There is no explosion however it does release fugitive emissions of methane.
I prefer the current site diesel site at the Yukon Energy office or across the road. I'm concerned about access to the other sites.	Thank you for the feedback. We will include this as part of our assessment of the project.
What is the difference between LNG and diesel?	There are three main differences: 1. LNG emits fewer greenhouse gas emissions 2. Diesel engines start up faster 3. Diesel engines respond better to changes in electricity load and are better suited to the future integration of renewables

	We've completed a detailed analysis between the three fuels. That information is available on a summary chart on our website, yukonenergy.ca/thermal.
Are there any micro-hydro projects?	There are no micro projects but there are small hydro projects. We are currently exploring two: Drury Creek and Atlin. Wind and solar are variable and therefore not reliable during emergencies or toe meet peak demands.
Who would be the owner of the third party LNG depot?	Ferus is looking at the potential of building an LNG deport near the Takhini site.
What about bringing LNG up to Skagway and driving it to Yukon from there?	It is something that LNG companies have considered and deemed not to be feasible.
I'm concerned about fire suppression at the Takhini substation location.	This is something that would be addressed if this was the chosen location. We would comply with regulations.
How is the battery storage project coming?	Technology is moving forward mostly around Lithium Ion batteries which have a 20 year life. The battery would not help with peak demands but would pick up the load in an emergency. We submitted an application to the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government.
Why are we still looking at fossil fuel projects as opposed to renewables?	Capacity. These projects are geared towards capacity. We need to plan to meet demand when we need it most (dark, cold winters for ex.) If a renewable unit goes down then we have a backup emergency unit.
Do you adjust demand based on different scenarios?	We looked at 20 various scenarios and this is the most likely scenario based on what we know (population and economic growth, electric heat and vehicles, etc.). Energy conservation is something we always look at.
Who is the Yukon Utilities Board?	They are a Regulatory Board that consists of Yukon Government appointed members.
What about DSM?	We have a DSM program but costs for the program were recently denied by the Yukon Utilities Board. We are asking the YUB to review that decision.

What else are you doing for renewables?	We are exploring a number of project including hydro, battery, thermal, hydro upgrades and storage. There is also a Yukon Government Independent Power Production policy that allows small producers to generate renewable electricity and sell it back to the grid.
If we have a portfolio that includes thermal and we look at cradle to grave would the full cost be more or less re: greenhouse gasses	*This answer was not known but will look into it.
Are solar panels useful or should I just insulate my house more?	It's better to insulate as solar in not reliable in an emergency in the middle of the winter.
What are our emergencies?	Loss of hydroelectricity (failure at one of the dams, primarily Aishihik), a fault on the transmission line between Aishihik and Whitehorse, when peak demands for electricity are more than what's available, weather events, when renewables aren't available.
Where does the current LNG plant fit into this? I thought this was supposed to be used as a back-up.	The existing LNG facility was built to replace old diesel generators that were coming to the end of their life. We are using LNG more this year than in the past to supplement the low water levels that we are currently facing. The fuel is inexpensive and clean.
What is the difference between energy and capacity?	Capacity is instantaneous and meets our need/peak at a moment in time. Energy is how much can be produced over the course of time.
In terms of equipment being used right now, is everything running efficiently right now?	We are currently upgrading the Whitehorse hydro plants which will give us more energy (allow us to produce more energy using the existing amount of water we have). We are also proposing the Southern Lakes Enhancement project to provide a low risk legacy. This would allow us to store more water in the fall months for use in the following winter (lowering our reliance on LNG and diesel during those months).
Regarding those affected, particularly at Marsh Lake, is buying out the public an option?	This has not been considered an option to date.

Are you looking at other options for the next 50 years?	We are also working on a portfolio of renewable and non-renewable projects that are needed to meet the increasing demand for electricity in Yukon. It includes this project, new hydro, upgrade and storage enhancements to existing hydro and a grid-scale battery.
Since Faro mine has been gone, we haven't had the large load in & out. Why can't Yukon Energy anticipate our long term needs?	Our regulator will not let us build ahead of demand. We are trying to progress with Southern Lakes enhancement projects however we are receiving some disinterest and appeals not to proceed from those in the area. We also explored a Next Generation Hydro but didn't get positive reception on that as well. We are currently moving forward with increasing the output of our current Whitehorse Hydro units and worked with the Government to being the Independent Power Production Program in place.
Is Yukon Energy leaning towards dual fuel?	No decision about the fuel type has been made. There are some benefits to dual-fuel as it can be placed at the old diesel location and utilize current LNG storage facility.
Are you going to build intermittent renewables?	We continue to explore the development of new small hydro projects and enhancing the storage capabilities of the hydro facilities we currently have. We explored wind, solar, biomass and other renewables as part of the 2016 Resource Plan, but they didn't fit into the portfolio because they are not dependable all year round in all types of weather.
It is poor optics that Yukon Energy is building two thermal projects back to back.	Thanks for the feedback. We recognize that concern.
If Yukon Energy is just in charge of capacity then who is in charge of energy?	Yukon Energy is the primary generator of power in Yukon. We are responsible for making sure there is enough energy and capacity available in the territory for what's needed.
If you connect to the North American Grid would you still do IPP?	We would honour existing contracts but there would no longer be a need for the Policy.
How do we get away from fossil fuels? We need to see a serious decline by 2040.	The biggest contributor of greenhouse gas emissions in Yukon is the transportation

	sector so that would be one area to focus on. In terms of electricity generation, on an isolated grid like ours we will always need some thermal energy in case of an emergency or when renewables aren't available.
Is Victoria Gold getting power year round?	Yes but the load shifts seasonally and they are producing some of their own power. In the case of an emergency they would get taken off the grid first.
If you have multiple diesel units how does the frequency work when they are talking to each other?	They can run as one big unit or separately.
What is the diesel vs. LNG ramp rate?	Diesel - 50 KW/second LNG – less than 20 KW/second. Slower but more efficient
What kind of grid monitoring does Yukon Energy have?	The grid is connected to SCADA.
What about nuclear?	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
We have to do this project because of decisions made 15 years ago while everyone continued to push towards long term hydro or nuclear.	No response.
What about the rent vs. purchase option?	We believe there are benefits to owning the generators and new facility regardless of the location and fuel type selected. Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset.

	By investing in an owned solution we can ensure that this additional power is always available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service
When will we see more info on the proposed hydro projects?	We are in the preliminary stages of that speaking to First Nation governments and other stakeholders in the proposed locations. More information will be shared more globally when we are further down the project path.
It's sad to own an electric car and have to use diesel to charge it.	We are many years away from the next big hydro unit and we need thermal as a backup in the interim.
I'm happy to see Yukon Energy has not given up on renewables.	Thanks for the feedback.
What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
Are four small windmills better than one large one?	Yes. Its spreads the risk (ex. If one goes down you still have 3) and large windmills are more expensive (building, maintenance etc.)
What happened to the Next Generation Hydro studies done years ago?	It failed. There was no First Nation support for the project on traditional territory.
Who pays for new hydro? Tax payers or Rate payers?	If there is no government contribution to the project, then it is left to electricity rate payers to pay for the project. If government were to provide a contribution to the project then it would also affect tax payers.
How does hydro fit into the plan? I'm concerned with demand and supply going forward.	We are exploring a number of project including hydro, battery, thermal, hydro upgrades and storage. There is also a Yukon Government Independent Power Production policy that allows small producers to generate renewable electricity and sell it back to the grid.

What is our current capacity?	Referred to the Need poster. Showed past renewable vs. thermal graphs. Discussed the capacity line being show being in the case of an emergency (loss of Aishihik) requirements. Discussed how mines are not included as part of the demand shown on the graph. Explained how the demand line includes assumption of some use of electric heat and vehicles.
There should be demand management programs specifically for people with electric heat in their homes.	Smart girds and smart homes take time and money. Peaks have been growing faster than average top loads. We are piloting a Residential Demand Response Pilot later this year were we'll be asking for volunteers to install peak shaving systems on their hot water tank and/or electric heat. We're interested to see the uptake and results of that.
What are the regulatory issues with New Hydro?	There was very little support by First Nations for the project on their traditional territory. In addition to that any new electricity project, like Next Gen Hydro would need to be reviewed and approved by YESAB.
Are First Nations interested in IPP (Independent Power Production)?	Yes, however not Hydro. Some want nuclear. Interest in geothermal near Carmacks despite high risk. Wind interest from Carcross Tagish First Nation on Montana Mountain. There are also other projects being considered by other First Nations.
What IPP (Independent Power Production) are out there?	4MW wind project on Haeckel Hill is in the works. Requires federal funding. Government would set the rate at 15.8 cents. Dawson is looking at resurrecting old hydro. There are also other wind and solar projects being considered.
What is the viability of IPP (Independent Power Production) business plans? For example when they aren't supplying power (solar in the winter)	An agreement will be in place forehand and this creates more opportunities for others to fill in the gaps.
Why burn diesel when you can burn LNG?	The LNG supply cost continues to come down making it more cost effective (35% cheaper). It is quieter and cleaner. Diesel starts up faster and is better suited to the integration of

	intermittent renewables (responds quicker to changing loads).
Can you explain the battery storage?	It would provide 40 MWH worth of power. Black start capabilities (start up from being completely off). System protection and benefits. Requires a small facility with seasonal control and can store renewables. We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
What are your plans for new hydro?	7-10 years away from 2 small hydro facilitates able to produce 8-10 MW each. Looking at expanding the Atlin facility and Drury Creek project.
Are you working with First Nations on hydro development?	Yes.
What is the best option for rates?	Thermal is the most cost-effective option to address our capacity need. It is the lowest cost solution. All rates increases are subject to approval by the Yukon Utilities Board.
What's the difference between capacity and energy?	Capacity is instantaneous and meets our need/peak at a moment in time. Energy is how much can be produced over the course of time.
What is the difference between LNG and diesel?	There are three main differences: 1. LNG emits fewer greenhouse gas emissions 2. Diesel engines start up faster 3. Diesel engines respond better to changes in electricity load and are better suited to the future integration of renewables We've completed a detailed analysis between the three fuels. That information is available on a summary chart on our website, yukonenergy.ca/thermal.
Which fuel is cheaper to build?	Diesel.
What does BC use?	A mix of resources including thermal for backup.

I don't have a preference for location, I just want fewer outages.	Thanks for the feedback. This project would certainly help prevent outages in case of an emergency or when peak demands for electricity outpace what is available with renewables.
What about biomass?	Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
Smart metering would be great for energy consumption	We are piloting a Residential Demand Response Program later this year which will help us see how much peak we can shift by remotely controlling the temperatures on hot water tanks and baseboard heat.
My LOCATION preference in order: 1. Across from LNG 2. Diesel Plant 3. Sewage Lagoon 4. Land fill (fire hazard and restricting access) 5. Takhini (noise for nearby residents) I prefer Diesel to LNG	Thank you for the feedback. We will include this as part of our assessment of the project.
We need for more programs for smart metering and conservation.	Thank you for that feedback. We offer a suite of energy conservation products but costs to offer those programs were recently denied by the Yukon Utilities Board. We are asking them to review their decision. We are proceeding with a Residential Demand Response Program later this year.
Can this project support the mines in 5-10 years?	Yes. However it's not the purpose of this project. This project could possibly be used for that purpose in 10 years when more dependable renewables come on.
I want to facility to be away from residents.	Thank you for the feedback. We will include this as part of our assessment of the project.
Will you have to put extra storage in the facility?	Yes. Enough storage for one day's supply.
What is the sound/noise level?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way.

	If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
Does biomass include recycling/garbage?	Yes. Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
What about solar panels?	A utility scale solar project is not great for dependable capacity which is our immediate need and would be addressed by this project.
What about battery?	We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
The Takhini location contradicts why people move to country residential.	Thank you for the feedback. We will include this as part of our assessment of the project.
What about Industrial land downtown?	That would need to be near existing power lines and where land is available.
What is the cheapest option?	Takhini. But we need to listen to the opinion of customers in the area and to obtain social license.

Population growth would drive this.	Yes, it certainly is one factor that we looked at to forecast the demand for electricity.
What two hydro projects are you considering?	Drury and Atlin.
What happened to wind?	The two units were over 20 years old. One unit is retired and the other is part of a proposed IPP project.
What about hydro?	We are looking at projects at Drury and Atlin.
What about biomass?	Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
Why is LNG now being used as the base load?	We are in a low water year where we need LNG is generate the electricity that hydro cannot.
Where are the renewables in the long term plan?	This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.
Why are we supplying the mine? Can't we let them create their own energy?	We have an obligation to serve all customers that require power. Mines are the reason for this project. They were not included in our demand forecasts because in case of an emergency we would disconnect the mine from the grid to be able to provide more power to other customers.
What if there was a policy with a stipulation that mines could not use thermal?	I expect it would drive up the cost of building and operating the mine.
It doesn't make sense to only run a $100 million plant for two weeks per year.	We need this plant to provide reliable power to Yukoners. Two weeks usage is based on normal conditions where there is average water levels. This plant may be used more in case of an emergency, to meet demands for power in low water years.
We are a small population on an isolated grid. If Yukon can't use renewables who can?	More than 90% of the electricity we generate today is renewable.

Why not keep renting?	We believe there are benefits to owning the generators and new facility regardless of the location and fuel type selected. Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset. By investing in an owned solution we can ensure that this additional power is always available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service
Is there a risk of stranded assets?	Possibly but there is also a risk to strand rental infrastructure.
What would be involved in putting rentals at Takhini?	The land would need to be cleared to make room for the rentals and the area would need to be made secure and safe.
How much backup time do you need to plan for now?	We store three days of fuel (continuous 24/7 runtime).
Where does your diesel come from?	North 60.
What is the scope of input in the survey?	We are looking for public input on the preferred location and fuel type.
Is renting a recent phenomenon?	We have been renting the last couple of years.
Are you taking feedback on your larger portfolio?	Today's input is specific to this project. We conducted a Yukon-wide public engagement on our larger portfolio as we were building our 2016 Resource Plan.
I would like to see thermal decreasing.	Thank you for your input. This project is part of a larger portfolio that we are working on that includes renewables.
Is Aishihik's supply tenuous?	Not particularly, but as our largest hydro facility we must plan for the case in which that

	plant goes down or we don't have access to it (transmission line failure).
What is your annual target for renewable use?	We aim to use the maximum of renewables we have currently each year. As part of our 2016 Resource Plan we identified a portfolio that is 98% renewable. This project and others we are working on are part of that plan.
Is the Yukon Utilities Board involved in this process?	Previously, yes as part of the Resource Plan. And costs for this project would need to be approved by them.
What's the deal with the battery?	Can hold 8 MW and provide a daily resource. We are exploring a grid-scale battery and have an application in front of the federal government to help us fund that project. A $19 million project with $10 million funded by the federal government. Battery is good for backup and to help levelize peak demands for power.
Are there solar farm sites being considered?	Solar was considered as part of our 2016 Resource Plan. Yukon Energy is not pursuing grid-scale solar because they only provide intermittent energy. Independent Power Producers are presently looking at constructing several solar farms.
Rentals create a problem of having less incentive to move toward renewables.	Thanks for that input.
Are we not vulnerable to climate change?	Changes such as permafrost will not affect the location site.
Why don't we have water meters to limit the amount of water we use?	That would be something that would need to be mandated by the City of Whitehorse.
I'm concerned that only fossil fuels are being considered as part of this project.	This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.
Are there subsidies for solar or wind development?	Through Yukon Government's Microgeneration and Independent Power Production Policies.

The Takhini site is surrounded by muskeg.	Thank you for the feedback. We will include this as part of our assessment of the project.
What about noise?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
Lots of wildlife in Takhini.	Thank you for the feedback. We will include this as part of our assessment of the project.
My preference is for the landfill or lagoon locations	Thank you for the feedback. We will include this as part of our assessment of the project.
I have concerns about road usage and possibility of spills near the Takhini site.	Thank you for the feedback. We will include this as part of our assessment of the project. In case of using LNG, there would be no spill to ground, the LNG would go into the air (with methane emissions). In case of a diesel spill, it would have an impact on the land.
Can LNG affect water supply?	Not specifically at this site. Some methods to extract LNG due require water resources.
Will this devalue property because of the noise?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner.

	Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
Does Yukon Energy have a preferred location?	No. We are currently just trying to get feedback from the public and assessing all of the options.
Why assume the loss of Aishihik?	It's a liability question, let's say we lose the biggest generation producer, can we still manage? Would we still be able to keep the lights on?
Are there other hydro projects happening?	We are looking at two: Drury and Atlin. If all were to go ahead smoothly those projects are still at least seven years away.
Concern about building a new dam and the impact on wildlife and draining rivers.	There was certainly be some impact to land. That's why every project goes through a rigorous review and process and even when it is operating, there are water management plans.
What about smaller renewable projects?	Yukon Government's Independent Power Production policy was rolled out 6 months ago which allows smaller producers to sell to the grid.
I want nuclear.	The use of nuclear to generate power would need to be approved by the Yukon Government before it is something that we would be able to explore and implement.
Yukon Government is advocating for electric heating.	This was factored into our load forecasts.
I don't want LNG. I want a long term solution. I wants renewables.	This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.
Why does LNG across from Yukon Energy have a red spot (on summary slide)?	The exhaust plume may be a potential hazard for air traffic.

Does peak power draw the current away from my appliances? My stove acts differently at 5:00pm.	No.
How much do know about biomass? Could this be an option? There is lots of wood at the landfill from construction projects.	Biomass is one option we explored in our 2016 Resource Plan, but it isn't suitable to provide that quick, dependable, dispatchable power we need during an emergency.
I don't like this consultation forum. I would prefer others in a group setting hearing lots of questions from others. I drive an electric car, use solar energy and have taken down trees in my yard but I'm afraid that these efforts will not mitigate fire due to fossil fuels?	Thank you for the feedback.
General comments from one participant: - Problems with ground water conditions - Do not want it at the Takhini site - Concern with the wildlife corridor around Takhini - There are too many surveys to keep track of - I'm concerned about the climate - I want to see small nuclear plants. - I don't want to see any more LNG - The survey format forces you to make a decision - GHG emissions a concern - DSM should be a priority - Need wind and energy storage and improved home insulation - Peak shaving - I'm concerned with GHGs	Thank you for the feedback. We will include this as part of our assessment of the project.

appendix a.1: post-it note comments on panels at open houses

June 1-6, 2019

Participant comment/question	Yukon Energy Response
TAKHINI LOCATION PANEL • Dangerous corner and blind hill when trucks are turning (nicknamed, MACH I HILL for good reason) • Takhini River Bridge is too small • Lots of wildlife in the area • Health and noise concerns • County residential. Residents for a reason • Increased traffic to the area • Decreased property value • Trails well used in that area • Wellness Centre • Muskeg in location • Tourism operations • Cranky hermits and artists • Excellent area for future development • Fire suppression • Site is on the top of a hill • Highway safety with trucks turning?	Thank you for your feedback. These comments will be considered as part of our project recommendation.

LAGOON LOCATION PANEL • Most preferred • Driving across bridge • Traffic congestion • Big trucks	Thank you for your feedback. These comments will be considered as part of our project recommendation.
LANDFILL LOCATION PANEL • Could improve dump road • No negative traffic effect • The landfill would increase the possibility of bio-mass generation on-site • Incinerators? • Would like to see upgrades to the road • Best site • Easy access for fuel trucks	Thank you for your feedback. These comments will be considered as part of our project recommendation.
DIESEL PLAN LOCATION PANEL • Preference for existing site • Use the waste heat in buildings	Thank you for your feedback. These comments will be considered as part of our project recommendation.
• Is there space?	
ACROSS FROM THE LNG STATION LOCATION PANEL • Use the waste heat in buildings (Yukon College, CGC, New Developments)	Thank you for your feedback. These comments will be considered as part of our project recommendation.
OTHER COMMENTS • Thorium small nuclear when available • Yes (reference to nuclear) • What about fugitive emissions of methane? How are they accounted for? • Spills go straight into the atmosphere. False. Not good. 120 times more potent than Co2 when first released. • Limited suppliers.	Thank you for your feedback. These comments will be considered as part of our project recommendation.

appendix b: door-knocking comments and questions

May 30-June 17, 2019

Participant comment/question	Yukon Energy Response
I want to see more renewables installed instead of fossil fuels.	I understand. We need this facility during emergencies, to meet peak demands for power, and for when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs. It's important to note that this new thermal facility will not provide all of the power we need to meet the increasing demands for power in Yukon. This project is one of many we are pursuing, some of which are renewables like the development of new sources of hydroelectricity.
I would like to see more renewables. What about geothermal?	Yukon Energy explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
My preference is for the Takhini site. Next would be at the diesel plant. I don't like the options across from the LNG facility, Landfill or Lagoon because of possible future recreation development there. The fuel option you select should be the cheapest one.	Thank you for your feedback. These comments will be considered as part of our project recommendation.

What about solar?	Building solar was considered as part of our 2016 Resource Plan. This project is specifically needed so that we can provide reliable power during emergencies, to help meet peak demands (especially during the winter), and when renewables aren't available. Solar is not a dependable source of power generation for these types of situations.
How loud will the new facility be?	If an LNG facility is built, it will be no louder than the existing LNG facility on Robert Service Way. If a diesel facility is built we expect it to be around 75 decibels loud when it runs (assuming you're standing about 10 feet away). 75 decibels is just a little louder than a vacuum cleaner. Regardless of its location, if a new diesel facility is found to be the best solution, it would be quieter than the existing diesel plant at the Whitehorse Rapids site. That site is louder because older and louder units are in there now.
I prefer that the generators stay where they are now (at the diesel plant in your parking lot) and for the dual-fuel option to be selected. I'm concerned about the increased traffic that might result at the other locations.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
I would like there to be more renewables.	I understand. We need this facility during emergencies, to meet peak demands for power, and for when hydroelectricity isn't available. We need a generation source that we can access immediately and that can be switched on at a moment's notice. Electricity generated using LNG, diesel or both (dual-fuel) is proven to be the most reliable and cost-effective solution to meet these needs. It's important to note that this new thermal facility will not provide all of the power we need to meet the increasing demands for power in Yukon. This project is one of many we are pursuing, some of which are renewables like the development of new sources of hydroelectricity.
What about safety?	We're committed to employee and public safety. All of our facilities are equipped with safety measures as outlined for the type of work we do to minimize risks to employee and public safety.
Would extra people be employed by this project?	The facility will only be manned when it is being used. Building the facility would certainly require the employment of contractors and procurement of goods.

Just keep the lights on.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
Don't build the plant at your existing location (diesel plant). It would be like you're putting all of your eggs in one basket"	Thank you for your feedback. These comments will be considered as part of our project recommendation.
Just build it.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
I'm new to the Yukon. Can I use LNG in my home like I use natural gas in Alberta?	That type of infrastructure doesn't exist now. Homes in Yukon are typically heated using diesel, propane, wood or electricity.
What is the cheapest option?	Over the 40-year life cycle, building and owning a diesel facility at the Takhini site.
Has a vendor been selected for this project?	No. We are still in the preliminary phases of this project.
What is the different between renting and owning?	We believe there are benefits to owning the generators and new facility regardless of the location and fuel type selected. Renting anything comes with risks. Think of it like renting a house vs. buying one. • Will there be enough rentals available when you need them? • Will the cost to rent increase? • What state will the rentals be when you get them? • And at what point does it make financial sense to invest the money you spend each year on a rental into an owned asset. By investing in an owned solution we can ensure that this additional power is always available when we need it. By owning the facility, we'll also be in a position to make sure that it is always maintained and ready for service
I'm disappointed that you are looking to use more fossil fuels. I would like there to be more renewables on the grid. My preference is for you to rent the generators so that the capital investment of building something new be used for the long-term development of renewables. The survey should have included more open-ended questions.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
I am deeply concerned about the Takhini site. This would be a huge infringement on our quality of life. I think it makes sense to have it either at your existing site, across the street or at the Landfill.	Thank you for your feedback. These comments will be considered as part of our project recommendation.

appendix c: online survey results

MAY 21 – JUNE 9, 2019

447 respondents

Q1. Tell us your preference for each of the following site location options for a new thermal electric generation facility. Put "1" for your first choice, followed by "2", "3", etc.

	Weighted score
At Yukon Energy's Whitehorse diesel plant	23.65
At the Whitehorse landfill	22.94
Beside Yukon Energy's Takhini Substation	19.53
Near the Whitehorse sewage lagoon	17.12
Across from Yukon Energy's LNG generating facilities	16.77

Q2. If you don't support any of these options, tell us why.

- 4 or 5
- Across from LNG - removes good usable land for residential, commercial and recreation.
- Air quality. If we need more toxins from LNG or diesel emissions at least move it out of Whitehorse valley.
- All of these are awesome. I especially like the Yukon Energy home near the dam because it's very visible and we should show it off!!!!
- Anywhere except beside the Takhini substation. This is a rural residential area and it will have direct impacts on those of us who live close to the substation.
- At very least, thus option process should not be considered without a more thorough inclusion of renewable integration. This to my mind is after the affect, more electrically heated homes, without much energy planning. We cannot underwrite continued climate change options of this nature to our energy menu. This very old school thinking and non-planning and support for petroleum options is not tenable in today's world climate crisis!
- Because we need to stop supporting fossil fuel usage and start constructing green energy projects
- Better to put the generators close to existing infrastructure
- Both the landfill site and lagoon site would require significant road upgrades. That's an unnecessary expense at the other site options.
- Carbon footprint, try solar, wind, or many other BETTER options that may cost a bit more upfront...why are we not looking forward?
- Contrary to the misconception of Yukon Energy that the only options are LNG and Diesel, far better options are available in non-fossil fuel alternatives. Why is Yukon Energy not taking a leadership role and developing alternate energy and storage solutions.
- Could we not use/expand the mine site backup systems to act as a redundant system?
- Demand will keep increasing the more power that is generated.

- Do NOT buy LNG plants.
- Do not take away the motocross track of the mud bog pits if you go across the road!
- Don't have enough info to choose
- Don't put it along Robert Service Way. This is the gateway to the city.
- Don't support any locations for further fossil fuel facilities. However, cumulative noise from the facility is already an issue in Riverdale - so lagoons or landfill are best options.
- Don't support your plan. You need to move forward with other sources: Geothermal Wind Solar... perhaps a new hydro damn (Skagway)
- Don't force your employees to work beside a landfill or a sewage lagoon.
- Don't live in Whitehorse so don't know those locations
- Don't want it inside the city limit
- Energy demand peaks are result of attracting mines and industries that get exempted from energy taxes. Residents get asked to reduce demand and still have to pay more because they aren't contributing significantly to economy like large industry. Utilities need to make money on energy supply and demand. No brainer. But industry doesn't keep the money in the Yukon but to shareholders investors (probably Yukon Energy is one) that aren't in the Yukon. Energy money escapes and that is not energy security.
- Generating energy with options which create additional carbon footprint is not something I support. If diesel is used in the valley it adds to the winter smog effect in Riverdale and downtown.
- Habitant Dawson je ne connais pas assez les enjeux de chaque secteur
- How big is this facility? 20MW?
- How can I choose an option if I don't know the pros and cons of each site and why are there only two choices: diesel or LNG. What about geo-thermal???? What about not putting all your eggs in one basket?
- I DON'T HAVE ANY PREFERENCES, YOU KNOW MORE THAN I DO WHERE TO PUT THE FACILITY, JUST DO IT.
- I absolutely do not support any addition of diesel or LNG. Please put this investment towards renewable energy!
- I am deeply disappointed to see Yukon Energy deploying more thermal energy without comparable progress on renewable energy projects.
- I am generally opposed to another electric generation facility that use non-renewable fuels, anywhere, no matter the location
- I am totally against generating more electricity from fossil fuels. Spend the budget you have on electrical generation that doesn't contribute to climate change and increasing your current problems with low water levels. You are just digging us deeper into a hole.
- I am totally opposed to another thermal electric generating facility. You should be investing in renewal energy on a large scale from now on
- I am uninformed and this not qualified to make this kind of choice. How many survey responders would be educated for this decision?
- I believe a lot of energy generated is wasted by the public, businesses and all levels of government here in the territory. Yukon Energy should be providing education and awareness regarding the use of energy. I am very frugal with my energy use so find it very frustrating that I have to pay for those who waste it.
- I believe that Yukon Energy should continue to use interim solutions until such time that it can bring renewable or sustainable resources on line such as wind, solar or bio-sourced. Work elsewhere in the world indicates that renewable and sustainable generation is now technically feasible and in the long term more

economical than burning fossil fuels. Most of the arguments about load balancing can be and are being addressed through some form of energy storage.

- I believe we need to look for alternative green energy solutions to help supply the Yukon's power. We are in a climate crisis and should not be building fuel reliant facilities in this day in age to move forward. Please offer more solar programming to households to generate more power to the grid.
- I do NOT support "thermal" generation of power. We do NOT need power generated by fossil fuel. Make a serious commitment to renewable energy. Use "smart metres" to even out peak loads e.g. incentives to use power in non-peak times. Invest in solar, wind, bio-mass, heat storage. Be an energy leader, not a dinosaur. Dawson Creek generates power with 32 windmills and contributes to the southern grid. Surely we could follow.
- I do not believe that constructing another thermal electric generation facility is the best choice for Yukonners. I believe that there are alternative, sustainable options that may be more expensive in the short term, but are better options. Prove to us that you have considered alternative energy generation and that they are all unfeasible. Feasibility based on lowest construction cost is not acceptable.
- I do not have enough information to make an intelligent choice.
- I do not support an investment in fossil fuel-based electricity. Why is there no discussion of Small Modular Reactors? https://smrroadmap.ca/ Has an analysis been done with regards to the benefits gained from $50million investment in energy conservation and storage?
- I do not support creating more infrastructure that generates energy that is poisoning our planet. We have potential for geothermal and solar - there must be battery capability available to store solar power. Sweden uses their landfill waste to generate electricity. There are a lot of alternatives.
- I do not support locating this proposed plant near the LNG generating facility or the diesel plant as there is already too much noise pollution and Visual eye sore there.
- I do not support new fossil fuel generation. We have a worsening situation with climate change and there is an urgent need to reduce energy consumption first, then focus on renewables such as solar, wind, pumped hydro, biomass, geothermal, etc.
- I do not support tahini substation because it would be the closest power generation to residential living. This should be the biggest consideration.
- I do not support the construction of a new facility that involves the use of either of the proposed fuels. We should be investing more in renewables to meet our electrical needs. Individuals can learn to reduce their power needs when necessary. I believe this whole initiative is in response to potential future industrial needs. This is a sham consultation as it is only giving people an opportunity to participate in a decision regarding location and not on how we would like to see power developed in the future.
- I do not support the idea of building generating station near Takhini substation. It is too far from town for servicing and as of a resident of the area, do not want to see a large facility at that location.
- I don't believe anything more should be added to near the end of the runway area. I tried to not include those but this form won't let me not give those options a value.
- I don't know enough to know which site makes the most sense or if this is a danger to the public so should be away from where people are.
- I don't really support these options because I believe that by now we should be doing renewables even if they are more expensive at least in the short term. And that is because

of the impending climate change crisis.

- I don't support LNG development, fracking is horrible for the environment and detrimental to the well-being of Yukon residents. Please consider renewable energy projects and investing in a clean sustainable future
- I don't support The Whitehorse Plant site or the LNG site for added infrastructure considering disaster planning (fire flood earthquake air or other transportation related incidents). As a Riverdale resident, trail and green space user, our enjoyment of our living space needs to be considered. The site and noise from additional generating stations should not be introduced. Installing capacity in other areas would seem to support contingencies in disaster planning as well as municipal / territorial growth and reduce future expansion of infrastructure to meet those demand scenarios.
- I don't support added thermal generation in general.
- I don't support adding more fossil fuel facilities at all. You and the YG need to move immediately to increase renewable energy availability, and to address demand side issue!
- I don't support any of these options. This is a step backwards. We need to start to use green renewable energy systems (not dams) for power. The new wind turbine project on Haeckle Hill was okayed two years ago and it's really time for this to be developed. Yukon Energy is greedy corporation that is more concerned with their profit than providing the territory with green renewable energy. It is absolutely a FACT that Yukon Energy wanted those trial wind turbines to fail, as the corporation failed to service them. Finalize the power purchase agreement and get those new turbines up.
- I don't support building a new thermal generating plant. Please look to renewable sources for supplementing electricity during times of high demand. Preferred location would depend on what kind of renewable energy source is chosen.
- I don't support non-renewable energy projects ANYWHERE
- I don't support the construction of this facility.
- I don't support these options, we need to act on climate change and follow the path of the future, which is generating electricity with green renewable energy systems.
- I don't believe that these are viable sustainable options with little foresight into the issue
- I don't know enough about it
- I don't support any of these options because installing fossil fuel generators in the middle of a climate emergency is an absolutely appalling decision. We should be investing this money in renewable energy.
- I don't support putting the site at the Takhini road location due to already increased traffic on the highway as-as, as well as interruption to water route use (canoe, jet boat, etc.)
- I don't think it should be adjacent to any residential areas
- I feel like you guys are the experts and should plan for where makes most sense... and where financial burden is less. You can make a more informed decision that joe blow on the street.
- I need more information -- does someone have to drive out to turn on the generators or is it just a question of turning a switch at the main office? If a person is needed, then the sewage lagoon location is the least practical. It would be nice to have fumes created away from the existing infrastructure though for those times when temperature inversions are in play.
- I only support putting any new generation at the Landfill, and also distribution generation beyond. Near the sewage lagoon is risky for fire. Across from the LNG plant is dangerously at the end of the runway

and further makes the Robert Service Way even more dangerous. If there was ever a fire at the south end of Whitehorse the YEC generating facilities, corporate offices, SCADA control system are all could go up in smoke. YEC's fire in 1996 should have taught YEC a lesson about putting all its diesel generating, offices, hydro, SCADA and LNG in all one place.

- I ranked the options because none of the above is not an option. However, the last thing the Yukon needs in a climate crisis is a discussion around new thermal capacity.
- I support having reliable source of electricity. I am sorry it has to be thermal but I accept this as a fact of life living in Yukon.
- I support only renewable energy
- I support renewable resources and am against long term investment on the reliance of fuel
- I support the city of Whitehorse
- I think it would be a much better idea to invest in wind energy and storage. There are a significant number of elders that have commented that windy days have increased and there is hardly a day that goes by where there is not a slight breeze.
- I think it would be good to focus resources on vertical / bladeless windmills and solar farms
- I think that you should be investing money in renewable resources - micro hydro, wind, solar, etc. - and not fossil fuels. Climate change is real, stop feeding the monster.
- I think we need to make more serious considerations into renewables in the nearer future
- I thought the new LNG plant was built as a backup?!
- I understand we need the energy, I would hope that perhaps in future the generation could be converted to using some of that 'garbage' at the landfill, so make access easy.
- I want to see liquid thorium reactor technology employed in the Yukon. Nuclear is reliable, and modern tech makes it safe. As for location, put it wherever makes the most sense.
- I would like to know why Yukon Energy is even considering Thermal energy. Thermal power plants play major role in energy generation and at the same time are also responsible for leaving a measurable carbon footprint in the atmosphere. Wood pellet/chip boiler: They are a sustainable fuel source and wood pellet/chip heating will not produce carbon dioxide emissions to harm the environment. The amount of the carbon dioxide emitted during the burning process is equivalent to the amount absorbed during the growth of the trees. Wood pellet boilers are energy efficient. Can you imagine all the fire smarting that could be completed and said wood provided as an energy source? You could kill two birds with one stone.
- I would prefer Takhini substation as if anything may happen at the main diesel plant heaven forbid in theory there would be a chance to have backup from this location, plus it is more access able by emergency personnel if there was a need
- I would prefer other renewables!
- I would prefer that none of these options be used. Instead Yukon Energy should be investing in Wind, Solar and biomass. One of each of these could generate base load so that the water in the river could be stored for use when nothing else ids available
- I would prefer that we generate electricity from renewable sources, e.g. more use of solar panels, energy from burning trash (which, unfortunately, is terribly renewable), wind power, even wood burning plus energy conservation measures.
- I'd like to see a better and more detailed plan for alternative energy sources, not just Andrew saying "we're working on it."
- I'm not going to support any of these until I

see more information about how you came to this conclusion and the options that were considered, including better Demand-side Management.

- Instead of diesel/LNG power I'd rather like to see an upgrade of/addition to existing hydro along with pushing forward wind and solar. Fossil fuels are/should be a thing of the past. If you'd do/have done that asking for a new thermal electric generation facility location would be obsolete.
- It should be located out of town as the new LNG plant contributes a lot of excess fog in the winter.
- Items four and five to remote for access
- L'emplacement d'une nouvelle centrale thermique devrait etre examinee en considerant un complexe multi-fonction. Avec la quantite grandissante de dechets de toutes sortes au territoire, il serait bon de considerer la construction d'une fournaise oa[1] les dechets pourraient etre transformes et le chauffage produit par cette activite, distribuee comme energie supplementaire a la centrale thermique proposee. Il faut agir maintenant pour reparer les dommages et aide notre environnement a se 'guerir'.
- LNG is fracking- use renewable energy. More solar and wind power
- LNG is not a cleaner / transition fuel, I do not support increasing Yukon's dependence on any fossil fuels especially when diverse renewable options are proven to work. Spend the tens of millions on infrastructure (smart grid?) that enables Yukon to benefit from proven solutions like Taku River Tlingit.
- Lagoon site too isolated. Existing plant and across to it are both too close to downtown and residential areas. These options are not good a good choice at all. I do not agree that I have to add a number.
- My preference would be that Yukon Energy stop relying on fossil fuels so heavily. The last LNG plant was supposed to be the last one, a stop-gap solution. Stop with the stop-gap solutions and find something else.
- NO LNG
- NO new investment in fossil fuels!!! YE has ample time to begin investing in solar, wind, and biomass. The thermal generation facility will take the same amount of time to get up and running. It is unconscionable that YE has not yet invested in renewable energy, and is now, once again, considering an investment in fossil fuel infrastructure.
- No more burning in Riverdale! It's dirty enough with the wood smoke.
- No more fossil fuel burning... Build wind, solar and geothermal energy infrastructure...!!!
- No more fossil fuel generating! Anywhere in The Yukon
- No new thermal electric generation facilities; get on with renewables. We need to see how Yukon Energy is moving away from fossil fuels. The 2016 resource plan needs to be updated to specifically show us. Keep renting back-up until renewables are in place.
- None of the above We need to be using renewable energy source and not spending money on a new out of date form of production of energy
- Not a penny should be spent until an equivalent funding for wind, solar and other renewable energy is allocated as a number one priority. The entire project should be assigned to a First Nation, such as the Teslin First Nation. I expected that a civil and possibly criminal lawsuit will eventually be mounted against the Yukon Energy Board, whose vision. Doesn't reach past their noses!
- Not at Yukon Energy's Whitehorse diesel plant or across from Yukon Energy's LNG generating facilities. If there was a catastrophic event in that area, all 3 would be out then.
- Not at an existing facility. A more spread out system is more robust
- Not beside the Takhini substation. It's not fair

to people who live there, and moved to a rural area

- Not enough information to comment intelligently. Not below the dam, near down town. It is smelly or noisy?
- On South access to keep truck traffic out of town. Takhini is worst option for road safety with rise in grade giving poor visibility. Also if LNG or blend is an option ability to share storage is present which will support current storage constraints.
- Outdated technology. Understand and invest in renewable energy sources. You have all the info.
- Please do not install in the flight path or close to it. Avoid putting all the eggs in one basket by being downstream of the dam.
- Please do not invest all of this time and money into continuing the use of fossil fuel back up stations. It has been a reactionary response for decades. Please invest into modern, renewable, carbon reducing, sustainable and creative sources of energy production. Our populations and energy needs continue to grow. A wise and forward thinking response to our rapidly changing world is separately needed instead of band aid reactionary decisions made out of desperation.
- Possibly we could look at geothermal?
- Predominant south wind in the summer, winds must also be considered in the cold winter months. You could smoke out all of downtown Whitehorse with diesel smoke, much worse than wood smoke.
- Prefer non-fossil fuel options and/or incentives to reduce peak demand. Peak pricing, for example.
- Reno and replace old diesels AS NEEDED in the current plant...the less costly alternative.
- Rent again and build more hydro
- Rental makes more sense rather than tying us to fossil fuels. Yes, we need back-up but rental makes more sense as we transition to more renewables on grid and hopefully to better storage options and or new technologies for back up. In the big picture the cost of rental vs. a new thermal plant is not that different and we know how hard those numbers are to estimate that far in the future.
- Resources must be put to renewables. Canada has agreed to cut emissions, and this plan does the complete opposite.
- Sewage lagoon depends on the bridge-not a good idea. Out of the way at Takhini.
- Sewage lagoon road is not adequate
- Sewage lagoon site would be difficult to access.
- Should be building more hydro instead
- Should be investing in solar by making it mandatory on all new buildings and affordable to being on older structures
- Silly to build downstream from a dam. Silly to live downstream from a dam, but I do. Why does the gas plant scream? Stop it!
- Stop building power generators that require out dated fuels. Start to seriously produce power with renewable fuels.
- Takhini Substation is located on the crest of a blind hill on a section of highway known for high speed driving by freight trucks, clandestine racers and travellers from the communities rushing to Whitehorse and is also a major thoroughfare for tourists and vacationers. The area has no industrial activities as it is home to livestock ranching, and tourism related business that are only viable in a quiet wilderness setting. The site abuts on a major wildlife corridor for woodland caribou, moose, grey wolves, marten, lynx, black bear and grizzlies travelling on their migrations to and from the Yukon River.
- The Yukon, Yukon Energy, and Yukon Government need to replace diesel, dual-fuel, and LNG for power generation. They need to move quickly to geo-thermal power, wind

power generation, solar power generation and the use of utility-scale battery storage, or PSH pumped-storage hydroelectricity, compressed air energy storage, or thermal storage like hot salt.

- The assumption that a short term fossil fuel based solution to the peak load issue is questionable. There has been too little consideration that a ROBUST DSM program will address the short term peak situation and provide more time for both consideration and development of no-fossil fuel remedies.
- The best option is to place these in the present facilities as it SHOULD be the most economical and easiest transition. Not certain about across the road as would YEC have to buy this property????
- The dump is too close to where I live, and I think it will change the trail area too dramatically. The Mt Mac trails are a local resource, and many businesses depend on the "full wilderness" quality of them, minutes from city streets. The same thing goes for the Takhini Substation- it's a beautiful accessible area, and I don't want to see it ruined.
- The landfill site is a traffic problem
- The lowest cost options seem to be an owned diesel generating facility. For some reason, the cheapest location is Takhini ($98.1M) and the most expensive is the Whitehorse Diesel Plant ($123.0M). Without knowing the details, these costs seem skewed and don't make sense since the cheapest option should logically be close to the Whitehorse Diesel Plant. Therefore, with the information I have, it is not possible to support any of the options.
- The sewage Lagoon would be too expensive as it is not close to a substation. The Whitehorse Land Fill is also unsuitable for the same reason as the sewage Lagoon.
- The sewage lagoon is an important location for wildlife, particularly as a rest and re-fueling stop for migratory birds. Further development there would have a significant negative impact in this regard.
- Thermal generation should be seen as a last resort. There are huge hydro resources available - use them smartly
- These surveys are crazy, choose locations without knowing fuel type or any of the design considerations involved. You realize that the choice of location should be based on sound engineering judgement right? As such, would not favor any location near the existing facilities or in town. Best location is Takhini, reduces transportation if dangerous goods and offloading away from people and facilities and away from Yukon River.
- This investment needs to go into renewable energy projects. It is beyond ludicrous to be putting more money into fossil fuels at this time. There are plenty of renewable energy options that are NOT being explored or invested in and it's the time to do it.
- This is not the kind of electricity generation I want to see in the Yukon. I am against using even more fossil fuels we currently do, especially while there is so much untapped potential in terms of micro hydro and biomass.
- This is the time to invest in renewable energy, not more fossil fuel energy. The world is screaming to get off fossil fuels, and as we grow electrical needs, it is an imperative to make sure investment is future-proof.
- This money should be spent on developing renewable energy. It is past time.
- Until I see an ambitious and realistic strategy to develop renewable energy resources, I prefer not to comment nor support additional non-renewable resource energy capacity generation.
- Upgrade hydroelectric power by increasing the size of already existing power stations/ water storage. The environmental damage will be minimal as the facilities are already established and holding water creating lake habitats. Hydro is a clean renewable energy,

the naysayers are unusually uneducated or biased. There will be some environmental impact but it will be minimal compared to pumping exhaust fumes into the air. Tell the public what they need, and in this case just do it, stop bending over for the squeaky wheels who don't want to listen to reason.

- Use renewables
- We don't need a new thermal plant, we need a renewable option. Why not wait a few years (keep renting generators) and explore geothermal? It's a great resource with minimal impact and it is very likely that the Yukon has great potential. And on top of that invest in storage options and encourage people to use energy in off-peak hours (through different rates). Why having years of consultation about other options to just ignore all this work and go back to fossil fuels???? Is that what you call public consultation? I can't believe this is even being considered as a permanent option. How can you ignore what's going on with climate change and depletion of resources?
- We have known about the lack of planning for long term energy needs due to community growth and new mines coming online for probably ten years or longer. This issue even hit the news periodically. Why the Energy providers in the Yukon have not acted upon predictable energy needs and planned accordingly is inconceivable. Work with First Nations (TRTN is already trying to become a small energy provider), Yukon, and federal government departments, and the private sector to find renewable solutions instead. Subsidized energy savings and private micro energy production may provide another small measure of relief.
- We need to be going renewables. The world scientist are telling us we must wean from fossil fuels as soon as possible. What is Yukon Energy doing investing in fossil fuel development? We need to develop geothermal in the Yukon... YOUR KIDS AND GRAND KIDS NEED it as well as mine. It is outrageous that your energy plan does not even mention climate disaster looming or your efforts to green the grid. Shame on Yukon Energy for their full support of long term fossil fuel in the Yukon. You should be ashamed ...and feel guilty every time you look at your kids and grand kids
- We need to be looking at other energy options that do not include burning fossil fuels. We need to be looking at peak hours pricing to encourage people to delay using energy during peak periods.
- We need to facilitate the use of renewables, not diesel or LNG.....wind, solar, geothermal.
- We need to have a solution that doesn't require any fossil fuels. An energy solution such as solar or wind or using more of the hydro that we already have set up
- We need to stop burning fossil fuels and seek out renewable energy instead.
- We need to stop burning fossil fuels, search for a green solution instead.
- We need to use renewable energy like wind, solar, geothermal. Period. If you force mines to produce their own power, we may have enough already. I am tired of paying fuel riders and higher rates than mines to subsidize their profit margins.
- We should be doing more to create renewable energy sources.
- We should be doing renewable energy, not fossil fuels. 12 year UN Panel of Climate Change Scientists to avert disaster. This is an emergency
- We should be investing in solar or wind. It's cheaper, more sustainable, and we have vast resources for then here.
- We should build another HYDRO ELECTRIC DAM and generate power/ electricity from hydro..... more environmentally friendly.....
- Whichever is most cost effective?
- Why are you not investing in more renewable energy sources?

- Why don't to use wind power or solar power?
- Why plan for thermal energy??? Let's plan for a clean new hydro site!
- Would prefer you don't build a plant that will run on fossil fuels, especially LNG!
- YEC MUST focus on renewable energy suites such as wind and biomass, for future power generation. I support diesel generation as backup only, and only as an interim measure, this can be at the current YEC facility. Further LNG should not be installed anywhere for backup (which it isn't suitable for) or generation.
- YEC needs to take Demand Side Management, in plain language, energy efficiency and conservation, much more seriously, use those techniques to spread out the peak demand into off-peak hours. Techniques such as remotely turning off hot water tanks using FM radio or other techniques during the morning demand peak in Riverdale and other compact densely-populated neighbourhoods. Put in LED streetlamps to cut consumption, put them on motion detectors. Awareness campaigns for block-heater timers, water tank insulation programmers, timers in the building codes so hot waters refill at night, all of these are
- proven techniques used in other jurisdictions. As well, current YEC facilities are all too close to both floatplane and conventional aircraft flight paths, so don't put more infrastructure there.
- YEC should also looks at small-scale nuclear or medium-hydro as options.
- You have LOTS of existing hydro to backstop an increase in renewables. Install new wind and solar capacity and use Aishihik provide emergency capacity when the renewables are not producing.
- You mention in Social Conditions for the LNG site that there is an exhaust plume to consider in regards the airport, I would suggest that this is a visible impact in any of the areas, so I would want the site to be further away from residential/recreation areas. The Landfill as second choice is with the consideration that perhaps garbage can be used as a fuel source (as in other locations).
- You should be doing biomass, biomass will need to be close to downtown.
- Yukon Energy should be exploring renewable energy sources not wasting money making us dependent on fossil fuels
- Yukon needs to move away from fossil fuels. I support paying more for green energy such as solar, wind, and more hydro.
- Yukoners feel lied to by YEC. We were told the existing LNG were simply 'back up' energy. Now they run near constantly in the winter and here we are discussing the expansion of LNG/Diesel fuels in spite of all science, logic and moral duty. We recognize it will be difficult to provide a reliable year round energy supply without it, but it must be done. The planet cannot sustain further expansion of fossil fuels.
- are there any plans for renewable energies?
- because we need to have renewables energy. I do not support any diesel, gas, long.
- climate change, pollution,
- don't care either way, whichever is most cost efficient? Also no idea what the footprint of it is or what it will look like so hard to comment in an informed way
- I don't want to see any fossil fuel plants being built, period. You must find a solution and kick the fossil fuel habit.
- I don't really support any of them
- I support the options AWAY from people's houses. There is no need for an LNG plant to be by the substation, directly beside people's homes.
- no preference
- people live near substation
- Sounds great, thank you!

- the other 4 would not be readily accessible in case of major incidents
- Thermal electric generation is inefficient and costly, no mention on how the heat source is to be supplied. I don't support any form of fossil fuel use when we have so much local hydro potential
- use a geo thermal options
- use the money to develop solar/hydro/wind option
- We need power when we need it!
- would support more work done on alternate energy sources rather than fossil fuels
- You and YG have had 10 years or more to get ready for predicted population growth. And Yukon Energy and YG have done little to prepare; other than build an LNG plant. I do not support this project at all. Put the money into renewables at once, even if it is late.

Q3. What is the ONE MOST IMPORTANT thing you would like Yukon Energy to consider regarding the location of a new thermal generation facility?

- Ability to be located near existing facilities to perhaps reduce FTE costs and ease of building without impacting neighbours as well as ease in supplying fuel and connecting to grid
- Ability to start units quickly when needed
- Access for the mechanics to service the equipment, the p126 diesel plant is ideal!!!
- Access to the site for maintenance and fueling
- Access, environmental impact of building a new site plus access.
- Accessibility
- Accessible for workers but not protesters. Probably important to consider not having it by the current facilities if it will be a backup.... but for refueling, maintenance and monitoring it makes sense to keep them close together.
- Air emissions.
- Air pollution. Noise pollution.
- Air quality for city residents, thermal energy is NOT clean energy
- Allocation and safety
- Allowing for even more growth in future
- As far as possible from residential neighbourhoods.
- Aside from the usual geo-technical considerations, the new facility should be located near current distribution facilities and lines.
- Away from the river
- Better to have the diesel plant and LNG generation facility in close proximity to each other. Easier and quicker to access in case of problems.
- Build or improve access roads.
- Choose a place where you can use wind or solar instead of fossil fuels.
- Climate Change = wildfires. Burn baby burn!
- Close to existing generating infrastructure I.e. the hydro plant in Whitehorse.
- Close to town
- Community impact during construction
- Compatibility with surrounding area of noise and emissions.
- Consider more renewable energy sources -- solar, wind, micro water power, geothermal. REDUCE DIESEL AND LNG!!!
- Consider the NIMBY factor. Keep it away from residences.
- Consider the accessibility and expansion room of the location. We continue to grow, and will continue to struggle to meet energy demands.
- Consider the location in terms of providing

back-up for the most people

- Consideration of this project as a short-term stepping stone toward the long-term use of renewable energy sources. The location should be amenable to eventually replacing the diesel generators with modern energy-storage solutions that become cost and space effective, be they batteries, compressed air, etc.
- Cost
- Cost and how that will impact my bill
- Cost effectiveness.
- Cost of access and maintenance.
- Cost, future possibility for expansion
- Cost, redundancy. Should all energy infrastructure be in one location? Better to have back up at another location.
- DONT BUILD IT!!!!
- Disturbing private property during and after construction.
- Do not build it anywhere. It is a false choice that citizens are being asked to make. The logical choice is renewable energy - NOW
- Do not build it.
- Do not diminish the esthetic beauty of Whitehorse and surrounding area. The LNG plant removed nice forested area right along the entryway to downtown Whitehorse and plunked a power plant there. Whitehorse... the wilderness city... Whitehorse has amazing visible beauty. Let's not let it slip away. It would be hard to get it back if it goes.
- Do not do it. Put the money into renewables. Wind/battery or other storage, more hydro. We should do demand
- Do not locate another fossil fuel burning plant in the Yukon anywhere.
- Don't build it on the Mayo Road by the Takhini substation
- Don't build it. Invest in renewables. Do it for the children.
- Don't build it. Invest in sustainable, renewable, green energy facilities: solar, wind, geothermal.
- Don't do it
- Don't do it.
- Don't place it under the approach flight path to the airport
- Don't put it where aircraft will crash into it.
- Don't build it.
- Don't put it in the city limits
- Ease of access and operational efficiencies.
- Ease of access from highway.
- Ease of access in case of emergency (fire at landfill, road washout towards sewage lagoon etc.)
- Ease of delivery of fuel. The lagoons or the dump would not be very nice in the winter to get fuel out there by b-train without tire chains for the hills and this is coming from a truck driver. The other options are all fine.
- Ease of operation and maintenance
- East to tie into the existing system.
- Easy Access
- Easy access
- Effective operation!
- Efficiencies, emissions and providing the backup needed for Whitehorse
- Efficiency
- Efficiency of power delivery
- Emergency. Do not like having all the electrical generation system in one place
- Engineering judgement
- Ensure that it requires minimal re-building of current infrastructure (e.g. roads) for access/ delivery of fuel and relatively easy access in case of emergency (e.g. fire/spill cleanup).
- Ensuring that the visibility from the road is blocked. As well, having the ability to increase size in order to meet future demands.
- Environment and socio-economic impact

- Environmental impact
- Environmental safety/protection
- Existing infrastructure
- Financial burden and if it is a worth it band aid until a long term greener solution is found
- Find a better future solution: more hydro, connect to the B.C. grid, more renewable
- energy, etc. I think somebody saw this coming. Poor planning by Yukon Energy.
- Fire safety
- Fits into existing infrastructure (industrial zoning, existing similar use--as with YEC diesel plant)
- Fossil fuels are DIRTY AND NOISY. We need renewable energy
- Furthest distance from people, especially homes.
- Future expansion of facility
- Future LNG storage / retail sales. Down the road we would like to be able to form a gas co-op similar to elsewhere on the prairies and supply gas heat
- Future planning.
- GHG emissions
- Generator noise; tanker truck traffic; cost (capital as well as O&M)
- Green energy - it fossil fuels
- Handy, not affected by major disasters, accessible, some security
- Have far enough away so that if one is knocked out because if something like an earthquake, the other will still be operational.
- Hide it, and build it to replace it with practical (affordable) options in the future.
- How it looks and that it isn't close to our back up drinking water sources
- How to best support existing operations and reduce road safety hazard and increase road safety.
- How to generate additional electricity without it!
- I am 100% against locating it beside the Takhini substation. This is a rural residential area and it will have direct impacts on those of us who live close to the substation. The people on Vista Road will look directly into the plant not to mention all the other people who live close to it. This is an industrial development that should be located far away from houses. I feel very strongly about this. I hope Yukon energy will listen to mine and my neighbours's feedback and not locate the plant around here. Thank you.
- I do not support new thermal generation. YEC has had years to develop a suite of renewable energy generation options and work with government on the IPP policy so don't use it as an excuse to make foolish investments in fossil fuel generation now.
- I do not support tahini substation because it would be the closest power generation to residential living. This should be the biggest consideration.
- I don't understand why you would build it anywhere but where you already have a diesel plant/generating facilities? Wouldn't that make the most sense? What am I missing? You haven't provided the reasons for why you've chosen these 5 options. But 1 and 2 seem like they would make the most sense.
- I feel that we need to include in this "insurance plan" the consideration of a dam breach ad for that reason I would like to see strong consideration given to elevation and geographical distance between the primary and secondary generation sites. This will also help in the event of fire activity that could cause infrastructure damage to some areas of town while others remain viable.
- I see that this project is already going ahead so I would suggest that your capital investment in the new generators be minimal. We don't want to invest heavily in

what soon make be outdated technology.

- I support renewable resources and am against long term investment on the reliance of fuel. Consider short term options until you're in a situation to invest in long term renewable options.
- I think the farthest away from a person's property the better. Existing site seems appropriate
- I think these locations already generate thermal energy.
- I think yukon energy should consider other forms of sustainable resources
- I would like Yukon Energy to use their existing thermal plant buildings at Whitehorse and Faro before building on new locations.
- Ideally the facility would be located away from people's homes
- If it needs to be put somewhere, make sure it's sited in a way that doesn't impact future development in that area.
- If necessary rent generators as you invest in renewable power.
- If you are talking about gas or oil generators, you are living in the past. Let's try living in this century.
- If you're going to do something like this, place it somewhere where it can function as a backup to the existing grid. Away from the current site makes the most sense, and the dump has easy access.
- Impact on residents (country residential)
- Impact on wildlife in surrounding areas.
- Impacts caused to nearby environment
- Impacts on the environment
- Integration with long term urban plan
- Is this really your only option
- It looks like the only place that you have selected that is directly beside residences is the Takhini option. You should not be affecting residential areas. ALL the other options are in commercial areas
- It must be renewable.
- It should be front and centre as a reminder that we aren't doing a good enough job to divest from fossil fuels.
- It should be located out of town
- It should be where everyone can see it. We shouldn't be hiding the energy project.
- It should not be done in lieu of DSM improvements and expanding hydro development encourage more use of electric heat and vehicles.
- It's hard to make an informed choice when there is no description from YEC on the benefits and drawbacks of each proposed location. Which locations are easiest to integrate with the existing system? What are the O&M implications for each site? Ease of access for fuel delivery? Site conditions suitable for building foundations and fuel storage tanks? Risks of impact from fuel spills or equipment failure? Not enough information for people to make an informed choice. So the results of the survey are not very useful in my opinion. The public doesn't have enough knowledge to properly weigh in.
- Its impact to environment and people
- It's only wire put it as far from civilization as possible.
- Jobs, revenue, and economy
- Keep it setback and away from main roads
- Keep it to the Whitehorse core area
- Klondike Highway would be a blind hill and dangerous for workers, residents and tourists.
- L'impact environueutaux et l'impact sur les propriete pirne proche
- LOCATION AWAY FROM HOMES.
- LOCATION DOESN'T MATTER, THE NEED FOR THE FACILITY IS THE PRIORITY, NOT WHERE.
- La production d'energie propre,

renouvelable qui n'est pas dommageable a l'environnement et qui entend utiliser les materiaux de dechets de concert avec d'autres ressources pour produire l'energie necessaire a maintenir nos besoins energetiques.

- Large trucks causing traffic issues going to the landfill or the Takhini subdivision
- Le moins de polution possible
- Let's locate this new plant close to the existing diesel/LNG plants where workers can quickly access it. Also the Takhini location is an unsafe location for fuel delivery being at the top of a hill which would create traffic accidents and congestion anytime fuel delivery takes place. Also the safety of storing fuel like diesel could pollute our fresh water supplies if you happen to have a tank issue. If LNG is the fuel what if a forest fire or explosion happens what would that mean for any close by residents? Let's locate this new plant away from any residential properties! It would lower property values for anyone within site! Are we going to be compensated for this and any future issues YEC will cause? Having the plant located closer to the work force would also be financially beneficial for YEC!
- Leverage existing site characteristics to minimize cost (e.g. do not build it by the lagoons where road maintenance and upgrading are required)
- Located away from view of major roadway and away from populated area.
- Location
- Loin de la population
- Long term environmental impact
- Looking at options that don't include burning fossil fuels.
- Low impact on environment
- Lower cost to build and do not effect city infrastructure. So in future hydro prices won't go up significantly.
- Lowest cost
- Lowest emissions
- Make use of existing infrastructure and minimize environmental and socio-economic effects.
- Making sure it's not an eyesore like the LNG plant. I'm for anything to make power as long as it's not ok the side of a main road downtown
- Methods for incorporating other forms of renewable, thermal generation (e.g. biomass CHP) into the infrastructure at a later date to reduce the amount of diesel or LNG burned to produce electricity.
- Minimal impact to environment
- Minimizing incremental impact
- More renewable energy
- Movement of LNG trucks.
- N/A
- N/A. I don't support this project.
- NOT HAVING ANY MORE FOSSIL FUEL BASED THERMAL ELECTRICITY GENERATION.
- Neighbors. Please don't put it near where people live.
- Neighbours and environment
- No comments
- Noise
- Noise and emissions
- Noise and stink to neighbors
- Noise for nearby residents. Ease of service for YEC staff.
- Noise for people living in the area
- Noise impacts on nearby residents due to generator operation and truck traffic.
- Noise pollution. Also, less or no impact on existing or planned neighbourhoods. Put solar on government owned and leased buildings. Higher incentive for private buildings to install solar.
- Noise pollution/ visual impact

- Noise, and local pollution effects
- Noise, pollution, climate change, renewables.
- Noise.... noise..... noise
- Noise/traffic
- Not building it anywhere
- Not disturb residential subdivisions
- Not doing thermal generation. But if you must - away from residential development.
- Not enough info to comment. I prefer a movement to renewable.
- Not in downtown (the river valley) because the smell of rotting eggs from the LNG plant can be detected throughout downtown, especially when the windows are open on a warm day with a very slight breeze bringing it wafting in from the South.
- Not in the City
- Not near residences.
- Not to build any at all; move to green, renewable energy projects. Finalize the power purchase agreement for the new proposed and accepted Haeckle Hill wind turbine project and get them built.
- Not to build it! Do not continue going down this road. Make the hard decision and be a leader and invest in the future.
- Not to further impact the subdivision of Riverdale and Downtown
- Not using anything other than rental units accompanied by a ROBUST DSM. The YUB review being the one, but temporary, impediment.
- Not visible, not using public land like across from the existing generation facilities.
- Nuclear power!
- Nuke plant instead
- Ongoing costs. Oh one more. Ability to add onto if required.
- Out of sight
- Out of site out of mind. Please don't let this be another eye sore
- Out of town farther away
- Please consider only renting the unit, so that funds are available to invest in alternatives.
- Please do not put the plant near the Takhini substation. There are many residences in this area. This would also mean potentially more tanker truck traffic having to cross the dangerous Takhini River Bridge on the North Klondike Highway, increasing the risk of a hazardous substance into a river.
- Please don't put it near people who live on the Mayo Road. We moved out of town for a reason, and this would destroy the peace and quiet of our neighbourhood!
- Pollution
- Potential for damage to river and surrounding environment
- Probably ongoing associative costs or continued availability of use of the area.
- Proper integration in the environment (noise control, aesthetics)
- Proximity to existing facilities.
- Proximity to existing production facilities for ease and timeliness of emergency maintenance and for consolidation of facilities security and monitoring.
- Proximity to the highest users: downtown Whitehorse is growing with infill of homes, subdivisions and businesses that all demand heavy electricity use.
- Proximity to the river
- Proximity to values at risk of noise pollution and spills. Consider the transportation of diesel required for the generators.
- Public Safety
- Put up a wind farm instead.
- Putting generating plants near significant sources of geothermal.
- Regardless of the location, rental generators are preferred to purchase units because renting minimizes capital investment and enables future savings when alternatives are

implemented.

- Reliability/availability of power
- Renewable resource if economically feasible
- Renewables.
- Rethink to whole process and get your act together better for a better work!
- Riverdale already has terrible air quality in the winter. Driving past the LNG units on Robert service a yellow emission from the LNG units is seen. I don't think the largest subdivision in the Yukon needs any more air pollution.
- Safe distance from residential areas
- Safety
- Safety and environment
- Safety and reduction of environmental footprint
- Safety for people and wildlife.
- Safety in case of an emergency and access to the plane without requiring access from a third party
- Safety of residents and the surrounding environment (air, water, earth)
- Safety of the public
- Safety- the mayo road location is on the crest of a hill. The trucks going in and out will be blind to traffic coming. There will need to be considerable modifications to the highway. Yukon Energy has all the infrastructure at the current LNG and diesel sites, why is it not obvious that this is where the expansion should be?
- Safety. Continuous information to public in a timely manner.
- Safety. i.e. - ease of access for workers, access to grid structures, cost.
- Scrap the whole plan of more fossil fuel burning!
- Security
- Security.
- See above and are there no other alternatives that would include wind, geothermal, solar?
- See above for location. Should the dam fail? How do you recover?
- See answer for Q2
- Share information about noise, pollution, traffic, light and other emissions from any new plant to help people understand what impact it could have. Also what about the birds? What impact on the ecosystem could a new plant have in these different location?
- Should be a back-up location for generation if something happens to current facility.
- Should be as far away as possible from people's homes.
- Should not be on prime serviceable land, if it can be located in a more remote, low-value location
- Should not be on the east side of the river.
- Social Considerations. The Environmental and Economic factors are pretty similar in all locations except for the LNG site.
- Social and wildlife needs
- Spread the infrastructure out.
- Stop allowing entire subdivisions installing electric baseboard heaters!
- Stop asking loaded question. Instead of what where to put new thermal ask Yukoners (ratepayers) what TYPE of generation they wish to see?
- Stop using diesel, dual-fuel, and LNG for power generation, quickly move to renewable power generation. Other countries are doing this, and it is successful.
- Stop using fossil fuels. But if you are using LNG, consider the blast radius, should something go wrong.
- TO NOT BUILD THIS SHIT
- Taking advantage of site's current designation for energy use; ease of access in emergency.
- That disturbance for wildlife and people is minimal
- That is doesn't require much infrastructure to connect it to the grid

- That it be renewable resources
- That it be temporary.
- That it is a temporary impermanent measure - this is why short term rental of diesel back-up is the best "transition" fuel for Yukon.
- That it is time to invest in other forms of renewable energy on a larger scale.
- That it not burn fossil fuels. Come up with a green alternative.
- That it should be able to operate independently. If there were an earthquake, flood or fire this should be away from the current plant
- That the generating facility be located where it is operationally most efficient for YEC.
- That the site be earthquake proof and far from rivers and streams.
- That this is temporary!
- The Environment
- The cheapest option available. This is only for backup during the timeframe where there are no other sources of electrical generation are available. It should be made a priority at Yukon Energy to commence with the plans for a new hydroelectric generating facility as this takes a long time and it seems that we are in the situation now due to lack of planning with respect to electrical generation meetings the needs of Yukoners now and in the future.
- The environment as this plant could be around for a long time
- The environmental impacts to plants, animals and people
- The important part of this is economics as we build it at existing plant we can replace the old diesels only as they reach the end of life (to do this before makes no economic sense). If we agree with some company to purchase dual-use (diesel and LNG) generating engines at the times when needed to change (displace old diesels at end of life) we should be able to get a better deal. To place it in the other areas would require either new housing or new transmission lines which are costly. WHY NOT USE THE EXISTING INFRASTRUCTURE INTELLIGENTLY?
- The landfill seems perfect. Absolutely NO to the Takhini Substation. It would have a tremendous impact on the area between mowing the area down to acquire the footprint required, to the large vehicle traffic. That area may not have species at risk but it is the wells-used greenspace for four different neighbourhoods, and is one of the two most important watershed corridors to the Yukon River (the other being Wolf Creek) in the Wilderness City. No. No. No. No. Did I mention the Whitehorse landfill is perfect? Yes. Yes. Yes. Yes.
- The least amount of disturbance to the public for noise and fumes
- The location should, if possible, allow for electricity to be routed to individual portions of the network, so that in the event of a major loss of generating capacity, service can be provided on a rotating basis, rather than having a network wide extended shutdown.
- The need for renewable energy and the need to reduce dependence on fossil fuels.
- The noise factor, is there any risk to people's health, has enough studies been done?
- The potential for renewable energy inputs
- The potential to use dual-fuel engines for the generators
- The transition away from fossil fuels.
- The winds in the seasons we will need the capacity. Low lying air in the winter months.
- Thermal is a misnomer, be honest with us. You mean 'some type of fossil fuel' and it's absurd in the face of the impending climate crisis.
- Thermal should be built and used as a last resort.
- Think about environmental risk mitigation as a prime consideration

- Think of community disasters and not putting all the eggs in one basket.
- This should be done in a way that positions it specifically as a short term solution. Given the impacts of climate change in the north, this must be done in a way that emphasizes its nature as a stop-gap measure on the road to increased renewable power generation capacity. For example, rental of diesel generators, rather than outright purchase.
- This site should be located to allow growth and multiple uses. It should be planned for the future that may not include a thermal plant but could include battery storage or other technologies.
- To be able to meet the demand with minimal power outages
- To not consider it. Consider massive electrical storage facilities, stockpile electricity or water or other energy storage means during periods of hydro surplus. Be the future. Inspire the world now.
- To stay on the highway corridor for easier/ cheaper fuel delivery
- To think about future facilities for renewable energy
- Total project cost
- Traffic
- Traffic issues and closeness to residential areas.
- Transportation of LNG not going through residential areas
- Try to keep your footprint as small as possible , utilize locations you already have to minimize impact
- Use LNG from the Yukon to save on shipping costs
- Use renewable sources! Wind solar or geothermal!
- Use renewables
- Use the Alberta noise standard
- Visible to the public for awareness and education.
- What are the EXACT costs of this new facility? Be transparent with rate payers and not have the same situation as we had with the LNG Storage facility near Whitehorse dam.
- What is most efficient for Yukon energy!!
- What is the true purpose - if we look at the power we provide to the mine sites and remove that amount are we producing enough? If not then yes we need a redundant system - however maybe the current hydro should be the backup and spend the $ on solar wind and geothermal?
- Where there is room to locate additional generation equipment in the future
- Wherever it can be most easily tied to the grid.
- Whether it is actually needed or not. If it is absolutely needed then some sort of cogeneration facility should be considered where it can be used to provide heat for buildings.
- Why are we choosing thermal electric generation?
- Why are you choosing an option that leaves a measurable carbon footprint? Why are you not choosing a renewable resource? Look at Teslin and their success - https://www.youtube.com/watch?v=YjzRJcmtfSk
- Why aren't we looking at bio fuels or other options? We are going backwards.....instead of looking at reducing our consumption or using sustainable and alternative energy sources we'll be producing more greenhouse gasses.
- Why not enter into an agreement with Skagway and add lines rather than fuel burning generators
- Why they are not doing renewables - batteries too.
- Wind and solar power. Or something where there is not fossil fuels.

- YEC needs to distribute its diesel generation away from YEC headquarters and YEC must not invest in anymore LNG.
- You must consider the effect on residence no matter where you put it. I know it is needed. It is crucially important that it is located in space that does not interfere with any current or future residential prospects.
- Yukon Energy should be choosing rented generators to minimize capital investment. It will also mean future savings as alternative energy sources are implemented.
- Yukon Energy should be exploring renewable energy sources not wasting money making us dependent on fossil fuels
- Yukon Energy needs to be investing in renewable energy rather than Thermal electricity generation
- Ability to co-gen: use waste heat from the diesels for other uses.
- am not seeing anywhere in this survey input options regarding rental or owning equipment
- avoid sound of diesel in town
- away from residents and in an already established area
- close to current facilities
- cost
- cost of operation & ownership renting short to long term is least desirable as all will cost many millions with no long term value
- costs
- Dangerous to put it near the dam. If it can be cheaply integrated into the Takhini substation that might be strategically better.
- do not build it
- Don't bother with a location. Go renewable. A new hydro dam.
- don't build it at all
- don't want one
- easy accessibility in case of emergencies and you need to get to the plant asap
- easy to access/maintain (for Yukon Energy), safe and secure
- efficiency of location (ability to use existing infrastructure, through-ways, access)
- ensure it's atmospheric pollution is minimized
- fast troubleshooting
- good access
- How does it impact local enviro re sound and sight? maybe best place is sewage lagoon
- impact on surrounding neighbourhoods, people and property
- increase capacity to 30KW for lower incremental cost or enable easy/cheap expansion
- invest in clean energy
- invest in renewable resources
- it is LNG free
- it is short sighted to consider additional use fossil fuel energy generation for the yukon
- it should not be near a populated area
- Keep Whitehorse power generation in one location.
- keep it as far away from residential areas as possible
- Keep it away from river. Dam is getting older. Good place for redundancy.
- keep it out of site
- Look into burning bio waste. Anything that cannot be composted may be burned at a very high temperature and these systems can expel very little toxins into the air. The hospital burns biohazards all the time.
- lowest cost for ongoing maintenance and capacity to expand
- lowest cost for purchase & upkeep
- noise
- noise and air pollution effects on nearby residents and land users
- Not to place it in a potential flood area in the

event of an earthquake. Below the level of the existing dam at the existing diesel plant is a bad location.

- not using nonrenewable sources so choose a location where renewables could be used or converted to in future
- operational certainty-----i.e. that operation would not be affected by problems at other power generating locations
- Our carbon footprint and the need for government to support efforts in moving away from our dependence on fossil fuels.
- pollution
- Practical and cost efficient.
- proximity to existing facilities for flexibility in switching and maintenance
- proximity to existing power grid
- Put it where it makes the most overall "sense". While the Takhini substation may be the most appealing to most people if the infrastructure is not there to carry the power back into the grid without a substantial upgrade, perhaps site 4 or 5 does make the most overall "sense"
- safety
- Secure redundancy in the event of some catastrophic event that knocks down part of the generating capacity.
- sustainability, community wellness
- That it doesn't directly impact air quality of residents nearby, and doesn't devastate the natural setting of our "wilderness city".
- the noise factor, it would have to be really quiet
- they should be leaders, not followers, in planning for the future of electricity generation
- up front cost
- use it only as a back-up and try to establish a strong renewable energy system
- visual incongruity
- who owns the land/ location relative to noise

Q4. Tell us your level of support for each of the following options:

LNG powered

	Frequency	Percent
Low support	191	42.73
Medium support	89	19.91
Strong support	132	29.53
Undecided	18	4.03
Not answered	17	3.80

Diesel powered

	Frequency	Percent
Low support	222	49.66
Medium support	118	26.40
Strong support	76	17.00
Undecided	14	3.13
Not answered	17	3.80

Dual-fuel powered (LNG + Diesel)

	Frequency	Percent
Low support	201	44.97
Medium support	102	22.82
Strong support	99	22.15
Undecided	25	5.59
Not answered	20	4.47

Q5. If you don't prefer any of these options tell us why.

- Again with the leading questions, how to have a preference when the fuel use has not been quantified...how much power? Is it base loaded, peak, only emergency? How could anyone have an opinion if this isn't identified?
- Again, the rest of the planet is getting away from fossil fuels. We have more renewable options available to us here than many places in the world. Wind conditions similar to Wind Valley in California, 360 known geothermal hot springs , more solar hours than many places currently using solar...yet we keep on the fuel bandwagon. It is time to try a little progress.
- Against increased use of fossil fuels. You lied to the public about the purpose of the LNG plant you have already installed. Yukon Energy has not been honest in assessing the carbon footprint of the LNG you have been buying already -- fugitive emissions from fracking and production have been ignored.
- Aren't we supposed to be going towards green energy?
- As before, would like more consideration given to alternate energy sources
- As long as this 'insurance plan' takes into consideration the ability to one-day reduce the use of diesel in the future.
- As mentioned previously, wind generation is long overdue and with the ability to store the energy in a much more efficient fashion it is a win. Wind generation would eliminate the need and any concerns with trucking in the fuel for diesel or LNG to the power plant, it is often windy here. Solar is not ideal because of the low light levels in the winter and frequent cloud cover.
- Avoid more LNG at all costs because of Fracking
- Because there are better options to protect our planet too,
- Because these are not green or renewable; this is contradictory to our future - economically and environmentally.
- Because we are in climate crisis we need to find alternative energy sources to help supply the grid
- Can we burn our garbage / mass-burn technology? http://www.metrovancouver.org/services/solid-waste/garbage-recycling/waste-to-energy-facility/what-is-wte/Pages/default.aspx Biochar? Hemp crops? Can we use solar panels? https://www.science.org.au/curious/video/ivanpah-solar-power-plant
- Can we please, for the love of Pete, start creating renewable energy sources? If this is only supposed to be backup energy, it seems like a good place to start.
- Climate change. It's time to move on from fossil fuels.
- Diesel because it would have the lowest carbon footprint if purchased from Alaska and have the least amount of trucking.
- Diesel is more carbon intensive
- Don't over complicate your engines with dual fuel. Choose a manufacturer that can supply local parts and service. This will save extreme costs over time.
- Each thermal option for emergency requirement is dependent on a fuel Yukon does not produce locally. In the event of highway closures or market disruption what storage requirements must be considered to satisfy a "worse case event"?
- En 2019, da» au changements climatiques et la pollution, nous devrions envisager un autre type d'energie. Deja durant les grands froids beaucoup de gens chauffent au bois, il faudrait limiter les emanations, particules, polluants dans l'air
- Energy consumption reductions should be more stringent. The use of renewable energy should be prioritized, and developed with a decentralization approach

- Environmentally - I suspect at local source of LNG would be the best (cleanest/efficient) solution. I don't know the environmental impact of an alternative fuel sources like garbage, or the feasibility of other sources like geothermal or wind/solar.
- Every one of these fuels needs to be hauled up the highway. Not to mention that they are in limited supply and pollute our environment. We need to be looking at trying to be more self sufficient. Why are we not looking at using solar, wind or even geothermal?
- Fossil fuels are literally destroying our planet - how can you be so closed minded to continue pursuing them? You're experts in energy - figure it out - do better! The Yukon is small and flexible, we should be a leader in renewable and creative energy solutions, not a laggard.
- Fossil fuels that aren't even generated locally. These options should be opened to the large industry users you are trying to float and generated at their locations. Sorry Whitehorse you need to curb your population of energy users to be truly effective on climate change and emergencies.
- Give the people a sign that renewable energy is soon being developed. Announce a project that will give the people hope that renewables are on the way. The windmills on Haeckel Hill not turning when we have an abundance of wind available is not showing us that renewable energy is an option that Yukon Energy is entertaining.
- Given the seriousness of the climate issue, we should be doing everything we can to move in the opposite direction of any of these fuel sources. I understand the importance of easily dispatched power, but we're past the point where that should be the primary concern.
- Go to renewables. i.e. water storage, geothermal, solar, wind etc. Any fossil fuel use will harm the environment and will keep us Canadians from reaching the Paris Agreement.
- Greener energy should be used.
- Hydro
- Hydro is the way to go.
- I am OK with both if it is used for emergency situations. For other situations, I strongly believe that we can plan for low water situations ... long term goal at least ... and get started with renewable energies. Look at Norway. While we cannot 100% copy their system, we can at least learn from them.
- I am concerned that the options of renewable (wind, solar) energy are not in the mix, nor another attempt at convincing Marsh Lakers to hold back an additional 2" of water to minimize the risk of low water in winter. PLUS someone needs to work on demand side management -- otherwise you can add to the power supply and
- people will gladly use it all up.
- I am deeply disappointed in the progress YEC has made in adding renewable energy capacity, and in promoting reduced demand.
- I am not overly supportive of any of the three options because I need more information. Is this additional capacity needed to support a growing residential market or is it simply to support new mines such as Victoria Gold to continue selling them cheaper electricity?
- I attended a meeting about using all the beetle killed trees for bio fuel (which would also be a fire smart initiative) just this winter. Why did we have a room full of people listening to this proposal and now we're talking about burning more fossil fuels?
- I believe that Yukon Energy should be developing more renewable energy, especially wind energy which is more abundant in winter. Our grid needs to have a more diverse supply portfolio and a larger buffer supply of renewable energy to help cover droughts.
- I do not like the options because we are still

relying on fossil fuels. The earth is on fire and climate change is all around us. We need to remove ourselves from finite resources and look at 100% renewable resources for our energy sources or we as a human population will cease to exist because of a made up intangible figure known as money. The model we have been using of bring cost effective is no longer valid. We need to be looking at long term stability for the human race while we still live this life of luxury

- I do not support any kind of these. only renewable energy
- I do not support any of these because the Yukon is at the forefront of climate change and we should be moving to making significant changes towards renewable energy. Show me Bio mass, show me solar, show me wind, and show me more hydro! What about Drury Creek?
- I do not support anymore the use of diesel, dual-fuel, and LNG for power generation. The Yukon, Yukon Energy, and Yukon Government needs to move quickly to geo-thermal power, wind power generation, solar power generation and the use of utility-scale battery storage, or PSH pumped-storage hydroelectricity, compressed air energy storage, or thermal storage like hot salt.
- I do not support fossil fuel generation as a first option. Further reductions in consumption through efficiency improvements and then renewables should come
- before fossil fuels
- I do not support investment in fossil fuels for Yukon, we are a jurisdiction heavily impacted by climate change. While this may be an economical option in the short term, heavy investment in renewable energy is preferred.
- I do not support the use of fossil fuels.
- I do not want to see fracking in the territory - This would be the next step in order to support increased LNG use. Re diesel - I would rather see my dollars being spent on alternative and renewable energy sources - diesel and LNG are easy fixes but have huge environmental impacts.
- I doesn't matter, they are all fossil fuels. Choose what is best for you from a balance of resilience (ease of use and reliability) and lower GHGs.
- I don't know enough about either to make an informed decision
- I don't prefer LNG because the Yukon government is trying to build a business case for gas exploration in the Yukon.
- I don't support options that include the burning of more fossil fuels. Get a system in place that supports proven renewable energy options such as wind, solar, hydro or in-stream/ current fed hydro.
- I don't think either of these options is a good investment in the future and may take away our capacity and even desire to move towards renewable energy.
- I don't think that increasing dependence on fossil fuel (either LNG or Diesel) is a responsible choice. We know that climate change is happening and that we need to reduce carbon emissions to mitigate the worst effects of climate change. Even if fossil fuels represents a small(ish) portion of our energy usage during peak times and emergencies, we need to take a leadership role and aim to reduce or even eliminate that portion, not increase it.
- I need more information. Can we consider more DSM and getting by with the backup facilities we have? Can we consider financing residential battery storage systems or Electric Vehicles as short term backup? Rather than using any existing permanent or rented thermal generation for regular loads (such as we have done all winter), why not consider a new cogeneration facility (or facilities) to provide this capacity and use existing thermal for backup.
- I only support renewable energy resources

- I prefer a capacity focused Demand Side Management program to greatly reduce or even remove the need for more diesel backup. This needs to be provided as
- an alternative.
- I prefer a wind / solar option and it's unbelievable that neither wind or solar has been considered as a viable option or backup.
- I prefer capacity focused demand side management program to remove the need for more fossil fuel backup.
- I prefer greener energy such as hydro/wind/solar/ETS
- I still think there could be more efforts in managing our existing infrastructure, such as a smarter grid, premium for power at certain times of the day, and discounts at others to help reduce peaking. Also, can we not use our existing water more efficiently but using smaller wheels, vs, few large wheels?
- I strongly believe that the Yukon should be putting effort toward renewable sources of energy, such as solar or wind, due to climate change. Thermal power generation is a half-hearted effort, and does not do very much in reducing emissions.
- I strongly prefer renewable energy sources, but I appreciate the need for backup. Diesel is best suited for backup, while LNG is best suited for base load. Burning fossil fuels for base load is an unacceptable plan to meet Yukon's energy needs. Also, this survey didn't ask me if I prefer YEC to rent or buy. This is the most important question, as renting minimizes upfront investment and keeps a strong financial incentive to shift to renewables. If we can install more hydro 5 years from now, we can rent fewer generators and avoid the major sunk cost of a stranded asset.
- I support all options for reliable energy.
- I support my investing in renewable energy, not fossil fuels.
- I support practical energy solutions. These are reliable. Solar and wind is unreliable. Storage is expensive. It is important to consider the overall economics and the cost to the consumer.
- I support renewable resources and am against long term investment on the reliance of fuel
- I support this
- I think there are alternative options beside fossil fuels - what happened to the Hydro projects that government invested in?
- I think there are very good options out there for fuel consumption that are
- renewable. We simply cannot continue to invest in oil and gas and must do our part to stop a climate collapse in the near future. Our lives depend on it as do our children.
- I think we should address the potential shortfall in energy but we should also begin working on the top rated sites for hydro generation such as Finlayson. It takes about 10 years for a totally new hydro facility to be build and we are part way through that 10 years as Finlayson has been identified as a top site. Let's cut a deal with the Kaska and get on with it.
- I understand the need for dependable capacity but don't support the use of fossil fuels. I'd like to see Yukon energy investing in renewable energy technologies.
- I want to know that you have considered alternatives. If a possible location is at the Whitehorse Landfill, have you considered a gasification plant at the land fill to produce a synthetic fuel that can be used for power generation? Direct immediate costs are not the most important thing to me.
- I want to see liquid thorium reactor technology employed in the Yukon. Nuclear is reliable, and modern tech makes it safe. The Yukon would be the perfect place to reply it, allowing us to have steady, reliable energy any time of the year. I know you

have a team of well-educated and informed people, but please don't ignore nuclear energy as an option just because you believe public opinion won't support it. Many didn't support the LNG plant, and you moved forward with it anyways.

» I want to see more renewables, particularly wind.

» I would actually prefer we go right to expanding generation from renewable sources. Presumably you don't think that is practical - I would like to know why. From my perspective, investing in expanding generation from wind, solar, geothermal and additional hydro is far preferable to investing more money in fossil fuel based generation.

» I would increase my level of support for LNG if it could be guaranteed NOT to be sourced from hydraulic fracturing. Also, your background material provided plant capital costs but not operational (energy) costs for the three fuel options - this would be useful information in ranking the fuels too.

» I would like Yukon Energy to look into renewables (solar? geothermal?) as options for additional energy.

» I would prefer an option that isn't related to fossil fuels at all. Solar storage? Wind storage? We absolutely need to invest in non-fossil fuel options, and stop the dependence on fossil fuels. Increase rates? Something to encourage people to

» make smarter choices with the power they use.

» I would prefer seeing non-fossil fuel as a backup.

» I would prefer that Yukon Energy continues to rent a generator as a backup. This provides an insurance plan, but ensures that developing alternative, long term solutions that shift our dependence away from fossil fuels remain a high priority.

» I would prefer that Yukon Energy would invest in installations that would use wind, solar and biomass to assist with the base load. If we had 25% of the energy generated by green (not Hydro) means it would take the pressure off of the hydro and allow us to take advantage of its energy storage capacity

» I would prefer that we would increase our use of renewable energy and decrease our use of fossil fuels

» I would prefer to see an increase in demand side management programs to reduce the need for thermal backup.

» I'd like to see a move away from fossil fuels. A nuclear facility in the old anvil mine site would be amazing.

» I'd prefer that you look at renewable alternatives, working towards phasing out diesel and not just substituting with another gas/oil option. LNG is still gas, not renewable, not environmentally conscious.

» I'm no expert.

» Ideally Yukon could explore zero-carbon options like small nuclear, but I know Yukon hippies aren't going to go for that. So the next best is LNG.

» If you have to have another emergency backup plant, then chose the one with the least emissions. Then build a biomass plant, we have a surplus of that and the ability to grow it.

» In your statement at top of the page you mention ZERO about the greenhouse gases problems associated with both diesel and natural gases far as climate change catastrophe goes. How dare you as an energy leader not also acknowledge the ongoing immense problems with the continued use of fossil fuels?

» Instead of diesel/LNG power I'd rather like to see an upgrade of/addition to existing hydro along with pushing forward wind and solar. Fossil fuels are/should be a thing of the past. If you'd do/have done that asking for a new thermal electric generation facility location would be obsolete.

- It does not appear that we have any choice, but to choose diesel or LNG. I just hope that efforts will continue to be made to reduce our dependency of fossil fuels by using alternate energy sources.
- It is essential that Yukon Energy work to integrate more renewable energy in to the Yukon grid, rather than building more thermal. This is a step in the wrong direction. If more energy is needed, there is a need to focus on demand-side management to reduce energy use overall, rather than just building more thermal generation.
- It is important to use renewable resources such as wind or solar or non-dam hydro even if cost is more.
- It is time to finally start investing only in renewable energy.
- It is time to move away from fossil fuels.
- It is time to utilize solar wind and fish friendly hydro production - time to actually take action on climate change issues!
- It is understandable that the need for meet power requirements for the Yukon is becoming critical, especially given the possibility of the loss of hydro from Aishihik. However, there should be every effort made to being on non-GHC emitting power sources on line to solve this issue. The effects of climate change are already being exerted in this region in a prominent manner and committing to an additional 40 year thermal program is entirely ill advised. Efforts and resources should be directed toward bringing online other renewable power sources and/or small-scale nuclear to make up the deficiency.
- It makes no sense to build a facility that relies on fuels that will become less available and hopefully next to obsolete in the future. Whitehorse and Yukon residents want clean solutions. We are innovators and should lead the pack. To invest in a large scale fossil fuel plant is as regressive as it gets. And remember: Yukoners said NO to fracking, so don't make us reliant on LNG.
- I'd actually prefer a mini-nuke but that's not on the table.
- I'm not against the use of fossil fuels but I would like to see the territory explore ways to lessen our reliance on them.
- L'aspect de la rentabilite devrait etre secondaire a la sauvegarde de l'environnement.
- LNG is terrible option and not more cost effective. Perpetual supply/inventory issues. Diesel infrastructure is robust in North with support systems established
- and readily available, unlike LNG.
- LNG is unstable and highly explosive, transport and storage is riskier than diesel which visibly pollutes, both have equal negatives.
- Lack of progress on renewable sources of energy is appalling. Thermal is short sighted and a stop-gap at best. This issue has been known for years, why hasn't actual effort gone into renewables?
- Lazy, not taking environmental concerns seriously
- LNG cause it is better for the environment
- Look at wind and solar
- More energy demand management is needed rather than more diesel back-ups. This needs to be an alternative.
- My concern on any of the above is are they coming from a clean source and as for the LNG not from fracking!
- Need to get off using dirty fuels
- Need to think of using water turbines and solar and no wind mills....
- Neither LNG nor diesel are ideal, but at least diesel avoids the use of fracking and released methane, as is the case with LNG.
- Neither are green solutions
- No LNG at all
- No More LNG. YEC has been promoting LNG as being easier on the Climate which

is absolutely false. LNG is created from Fracked methane and that industry has never accounted for the massive amounts of fugitive emissions of methane. Methane is 120 X more potent ghg that CO2 when it is first released and degrades to 80X after 20 years, it has to be in the atmosphere for 100 years before it degrades to the Oil Industry's claim of 32X more potent. YEC's LNG plant and all the associated methane spillage that has occurred when trucking it up in open thermos tanks from Delta BC and the most recent methane spill on the Alaska Highway have made YEC the biggest GHG emitter in Yukon history if you take the potency of unburned methane. YEC LNG Plant is nothing but a climate change machine and it is the reason why our hydro plants are challenged. We need to build energy storage in everyone's homes and businesses. We need a smart grid, we need YEC to supply us with renewable energy that meets all our needs for transportation

- Non-renewable energy would prefer a renewable source
- Non-renewable fuels contribute to climate change. Yukon should have a global responsibility to reduce emissions.
- None are nuclear
- None of them are renewable sources
- None of them are renewable. Start taking wind, hydrothermal and other generation options seriously.
- None of these are green! These are all fossil fuels. Given that our average temperature is raising faster than the rest of the world, we need to make a strong stand AGAINST fossil fuels.
- Not sustainable carbon emissions
- Nuclear is cleaner - Yukon needs to move into the future not keep using old dirty tech
- Partner with Skagway
- Per comments made in earlier responses. Diesel is better than LNG in ANY instance due to well established methane considerations. The limited cost considerations by YEC and YUB to date are known to be insufficient.
- Please consider climate change- no fossil fuels!
- Please do not invest all of this time and money into continuing the use of fossil fuel back up stations. It has been a reactionary response for decades. Please invest into modern, renewable, carbon reducing, sustainable and creative sources of energy production. Our populations and energy needs continue to grow. A wise and forward thinking response to our rapidly changing world is separately needed instead of band aid reactionary decisions made out of desperation.
- Please explore other options but not ground heat. Complete disaster in Riverdale in the early 2000s with broken water and sewer pipes.
- Please invest in renewables. Our planet and our children's futures are at risk. Please do not build this facility
- Polluting fuels are contributing to climate change. We should be developing large scale renewable energy projects instead
- Pollution & unreliable transport of fuel if the highway closes.
- Preclude alternatives for 40 years
- Refer back to question one....
- Relying on fossil fuels that are transported up the highway increases our dependence not only on fossil fuels but on the transportation corridor. I support investing in producing energy locally.
- Relying on fossil fuels that have to be extracted by fracking or conventional means is like taking a giant step backwards in this era of awareness of the impacts of climate change. Then having to burn huge amounts of diesel fuel to truck the fossil fuels up the highway thousands of kilometers does not make any sense to me. It seems

unconscionable to me, given the cost and carbon footprint of this method. Please explore renewable sources of resources that we have plenty of right here in the Yukon: wind and solar.

- Renewable energy is preferred.
- Renewable energy makes more sense in the long term. Geothermal in particular has the advantage of steady draw without having a large dependence on wind or solar events.
- Renewable energy prices are now cheaper than fossil fuels. Build a massive battery energy storage facility and charge it up ready to use in emergencies and in peak times. We have the technology, it would be foolish to build more fossil fuel burning generators!
- Renewable please, long term resilient time-proof solutions. Higher cost up front, lower cost long term, on more fronts than monetary.
- See above
- See answer for Q2
- See previous answers
- See previous answers. Any new infrastructure development MUST be for renewable energy. Rent diesel generators, if necessary, in the meantime. There has been ample time already, to get renewable energy (wind, solar, and biomass) installed for the increasing needs of Yukoners.
- Should not be building more fossil fuel generation. Base load renewables should be augmented so that existing thermal can cover peak again (instead of using LNG to cover base load as YEC is currently doing)
- Should spend the $ on solar wind or geothermal
- So much investment in fossil fuels is disappointing.
- Solar or wind?
- Still prefer renewables.
- Stop investing in fossil fuels. If you don't stop, Yukoners are going to make sure that you can no longer have a monopoly on power. Invest in biomass.
- Stop using fossil fuels
- Strengthen the medium to long term strategy for increased renewables instead of continuing on the short sighted fossil fuel strategy
- Support all. But it's really time to consider nuclear throughout Yukon. Also, especially given that Site C in BC is going ahead, we should also look at tying into the BC grid.
- Sweden uses bio-fuels to generate electricity. In Germany solar produces less power per square foot of PV than the Yukon can, yet Germany produces massive amounts of solar on their grid. Micro-hydro streams abound in the Yukon near grids, yet they are not developed. Wind is practically being ignored. Yukon Energy always explains why they are not pursuing these renewable options, yet others are doing them. Yukon Energy needs to understand and accept that CO2 is going to destroy our climate and economies, and that they have to play a role in solving the problem of CO2 and not contribute to it. Please start thinking outside your limited scope of vision.
- Tapering off in investments into LNG may rise purchase cost of fuel/transportation. The Social Cost of Carbon will increase as the effects of climate change worsen. Why would we go non-renewable when we have enough renewable energy in our own backyard? There is no focus on being more self-sustaining while also going green. I understand we are outpacing our electricity output, but a lack of investment in renewable energy will short us in the long run. YE can see the energy growth needs and projections but has only now decided to take action. If we needed something done 10 years ago it should be up to YEC to make things work. Now we are in a tight position and I feel as though I am being pushed towards two options I do not want because we lack the time to create a proper facility. If we build

LNG/Diesel/Dual now, when will we ever get a renewable plant? In 40 years when we have outpaced ourselves again? Not having a green option anywhere in this survey is insulting. I want to see a continuation into geothermal e

- The LNG plant was grossly overpriced coming in at over 50 million dollars for only 15 MW of generation and it has been mechanically unreliable and very
- costly since it was constructed. With no black start capabilities it would be a big mistake to repeat the situation!
- The Yukon needs to move to renewable and sustainable energy sources. This can and should be done. It should be the priority for Yukon Energy!
- The current approach does nothing to address the urgent need to reduce dependence on fossil fuels. Time to get into the 21 century and put all that engineering expertise to work towards renewables.
- The first LNG was sold to the public as replacement for the old diesels, now we have opened the door to fracking in the Yukon to save transportation costs. No surprise to anyone who was listening. Writing was on the wall when we were misled from the start. We still breathe and listen to diesel generators all winter and now spring, summer and fall.
- The most cost effective method should be used.
- There are other options including charging more for high-peak electricity use so people would do laundry and some other activities at low-peak times. Also more wind and solar and the extension from Atlin not to mention putting some money into geothermal research. The test site at the Hot Springs looks like it warrants further research. There is a map prepared by geologists of likely sites. It would save a lot of money, lessen our carbon footprint and be available as long as the earth is viable.
- Thermal power is responsible for leaving a measurable carbon footprint in the atmosphere. Wood pellet/chip boilers: They are a sustainable fuel source and wood pellet/chip heating will not produce carbon dioxide emissions to harm the environment. The amount of the carbon dioxide emitted during the burning process is equivalent to the amount absorbed during the growth of the trees. They are energy efficient. Can you imagine all the fire smarting that could be completed and said wood provided as an energy source? You could kill two birds with one stone. https://www.youtube.com/watch?v=YjzRJcmtfSk
- They are all nonrenewable and are destructive in many different ways
- They are all petroleum based and I see no evidence of an integrated energy supply plan. And, much of these petroleum products are being fracked and over supported by government subsidies, both in Northern BC and Alberta!
- They are non-renewable.
- Think diesel can be used by itself while long needs diesel to get 'started'
- This is a business as usual solution. We need to be divesting from fossil fuels.
- This is a typical one-option after the fact survey by a government entity: Politicians, government officials and management at YEC have been avoiding decisions for years - while being busy with inefficient and unending consultation, and political correct statements. The Yukon has a huge hydropower potential - the options are clear and were recently documented. But in a territory the size of Spain and only 37,000 people we appear to be unable to build a single new run of the river project? Any new power plant will be a negotiated compromise - of which a new thermal plant is clearly the worst. It has a negative triple bottom line. Too high a price for political indecision.
- This is not the kind of electricity generation

I want to see in the Yukon. I am against using even more fossil fuels we currently do, especially while there is so much untapped potential in terms of micro hydro and biomass.

- This is supposed to be only in the short term and only as required. Therefore, these methods of producing power should not be used very much and therefore the emissions should be relatively low. A long term plan needs to be made to produce electricity in the future that meets our needs without the use of diesel and/or LNG sources.
- This should be temporary...
- This very survey is trapped in old school approaches to energy. The government needs to get out of the 20th century and think about the climate crisis. There are other options -- get creative.
- Too expensive for customers.
- Unfortunately as an isolated grid we need RELIABLE back-up even if YEC will use this to power up the mines as we all well know.
- Unfortunately you did not offer â€œno supportâ€in question 4. As explained in my answer to question 2, the current energy shortage is a result of extremely poor planning. I agree thermal power could be a quick fix to a problem that need not exist today if you had done your planning. However, as Northerners we already have an extreme carbon footprint. To even consider enlarging this footprint is a terribly wrong policy decision. Put more resources into R&D of solutions that are less environmentally devastating.
- Use renewable energy sources, allow for more Micro generation
- Use renewables
- Use solar and wind use renewable energy that does not pollute.
- We are in a climate crisis. It is time for 100% renewable energy.
- We have renewable energy options in Yukon. The energy is free, once the infrastructure is built. LNG has far too many externalized costs: water contamination, methane escapement. The fossil fuel industry is over-subsidized, and over-polluting. Per-capita, Canadians are huge GHG emitters. We want the viable options that exist.
- We have to start research and development on alternate energy solutions - solar, wind. To just go with the “traditional” methods as above selections indicate is not good enough for a future Yukon.
- We must explore alternatives to fossil fuels
- We need more renewable energy. We need incentives to shift power use so we don’t have extreme peaks.
- We need to be exploring other energy options that do not include the burning of fossil fuels.
- We need to focus on renewal energy! I’d rather spend MORE on something renewal and more ecofriendly than further contributing to global warming. I’m disappointed in Yukon energy for going this route.
- We need to move forward along with other progressive countries, like Norway, Germany, and Costa Rica. Let us be an example for Canada. Both Diesel and LNG are outdated, finite, and come with a heavy price paid for transport, and extraction. Wind and Sun are free, and although may seem expensive to set up at the start, will be more economical in the long run.
- We need to stop burning fossil fuels.
- We really need to be building a future for energy for the territory that moves away from fossil fuels. I understand the need, and it’s imperative that we change our energy structure.
- We should be build up more renewables in a climate emergency. As we get closer to the end of the 12 yrs, electricity generators will not be allowed to use thermal, I predict.

- We should be building another Hydroelectric Dam. Clean energy.
- We should be developing alternative sources of non-fossil fuel derived power to combat climate change (e.g. geo-thermal, solar). As a back-up source fossil fuel
- is fine but for long-term planning this is an irresponsible choice.
- We should be doing more to use renewable energy sources
- We should be investing in renewable sources and storage options!
- We should be investing in renewables and storage instead of thermal. There is a climate emergency on!
- We should be investing in solar and wind. We have so much sunlight and wind in Whitehorse. Alberta is building solar facilities to generate 100MW for $100 million. That is five times the power for cheaper than the proposals I see here.
- We should be looking at renewable energy sources, such as geothermal or hydro
- We should be moving away from fossil fuels not spending tons of money on new generation. Why is all the installed solar not allowing for extra storage of water in summer? What happened to the southern lakes enhancement? That needs to be back on the table. With first nations proving alternative green energies can work in the North, Yukon Energy needs to be doing the same.
- We should build pumped storage that drains upstream of the Whitehorse dam, so the water gets used twice
- We should investigate mini nuclear
- We should not be putting public money into more fossil fuel consumption. Energy efficiency and conservation can free up significant 'negawatts' of currently-wasted KWHRS of power, it is in fact, the cheapest source of energy. Energy storage, including thermal storage, needs to be investigated.
- We should use renewables for the reasons I stated earlier.
- We urgently need to move away from fossil-fuels, both for political and environmental reasons. There are alternatives: A- Micro hydro power plants. B- Existing hydro power plant(s) could generate hydrogen through electrolysis during low demand seasons, and store it in existing LNG tanks to be used in high demand seasons. C- Plastic garbage is a big problem in the Yukon. Why not use this plastic for generating power. The technology exists. Melted plastic is used much like diesel fuel. Install catalytic converters to reduce air pollution. D- How about thorium generators, a low risk non-polluting nuclear type of reactor. It's been in existence for decades. The north would be ideal for investing in a long-term thorium plant.
- While I support temporarily diesel I feel that Yukon has to move toward renewable energy. I have lived 35 years in Yukon. People have talked about renewable energy for many years. There were plans for wind energy facilities that were ready to roll. I even work as a wildlife technician to evaluate impact of wind tower on migratory birds in 1997 and there were no impacts. That has been a long time to come. How come we still have to wait for actions on which the rest of the world is moving on? Yukon we can do better.
- Why does it makes sense to put in a diesel plant when millions have just been invested in LNG generating plant? Why not stick with that?
- Why is there not a "no support" option? We do not support LNG at all.
- Why not explore renewables. Solar and wind and geothermal. Our territory is experiencing unprecedented impacts as a result of climate change. I work in northern Yukon where the permafrost is melting out. Why are we becoming more dependent on fossil fuels when we could be exploring alternative energy sources in Yukon?

- Why not investigate more renewable options and if you have already done so this message hasn't been effectively communicate.
- Why not look at a few other alternatives: - use waste plastic etc. for thermal generation. Can be done with suitable investment in scrubbers so there is no pollution impact and will solve two problems with one plant. If not enough waste, can import instead of Canada sending it abroad. - use excess power in summer to produce hydrogen, store for peak demands
- Why not look at options that would reduce dependency on fossil fuel? Take the time to plan other options. Residents have been requesting this for years.
- Why not nuclear?
- Why not nuclear? Or steam generators... have we looked into all available options?
- Worried about the health impact
- Would love to see a greener solution happen
- Would prefer some other form of back-up and an emphasis on new seasonal storage options and more renewables on grid (to support heating and transportation loads)
- You need to develop renewable sources of energy, not fossil fuel.
- You should be focusing on renewable energy such as micro hydro, solar or wind,
- and not fossil fuels. Thanks for trying to destroy the planet faster. Be a leader!
- Yukon Conservation Society indicates that this is the most environmentally friendly fuel source, when all is considered.
- Yukon Energy is supposed to be working away from Fossil Fuels. The spikes in charges for diesel in the winter are unacceptable. I would rather pay more for good energy all year than have unexpected charges. It is easier to plan a budget on consistent monthly bills. These spikes really hurts those on limited incomes, particularly seniors, single parents and those who work in industries that don't work during the cold snaps when the electric bill spikes. Looking at your stats, hydro is surprisingly low. Is there no way to invest to make the hydro more efficient? There's so much water spilling out and all that energy is going downstream uncaptured. Could additional generation occur downstream of the dam? Investing in fossil fuels seems short-sighted, and I imagine the price of diesel is going to rise to a point that is unaffordable.
- Yukon Energy must focus on developing reliable renewable sources - and do it now. Calling this an 'emergency' contingency is just an excuse to burn more fossil fuels.
- Yukon Energy should be exploring renewable energy sources not wasting money making us dependent on fossil fuels
- Yukon Energy should be paving the way for a renewable Yukon. I don't support the ongoing and INCREASED use of fossil fuels.
- Zero support for LNG - not low. Diesel only as backup and only as interim. Dual - no because absolutely do not support LNG, it is not a backup fuel and we must invest in renewable energy not fossil fuels.
- another hydro plant would be more environmentally friendly
- because we don't need to increase our dependence in dirty and costly energy production
- burning fossil fuels is not the way to support--develop and use non-fossil fuel sources
- climate change
- climate change, pollution
- In 2019 we must consider future GHG emissions when choosing a power source. Although I appreciate the difficult conditions that Whitehorse faces especially during the winter, I strong believe that a renewable option would be much better. Considering options such as other hydro sources (Taku River Tlingit First Nation has a surplus of

electricity and would love to be hooked up to the Yukon grid if I am not mistaken...) or other alternative renewable generation's options. Battery storage? Innovative storage technologies are coming out of Canadian universities and this could be a great option to put a call out to see if something could be suitable. ANYTHING that removes reliance on fossil fuels would be preferable.

- it would be noisy and smelly
- les options ve sout pas bonne pou environment et out de besain de source exterue
- no comment to add here
- non renouvelable
- None of them are environmentally friendly; they will all only increase our carbon footprint.
- nuclear is much better
- preferred location next to the landfill for future options of moving into RNG i.e. methane from combustibles
- The best solution is the southern lake storage concept. However well connected NIMBYS prevent this concept from going forward
- The fact diesel is being used as an option shows that people are stuck in the Stone Age...embarrassing.
- there are better options using renewable resources
- They all need fossil fuels; and I say no to their use.
- they are not renewable or green
- What about geothermal energy? Is it possible here?

Q6. What is the ONE MOST IMPORTANT thing you would like Yukon Energy to consider regarding the type of fuel to be used to power a new thermal electricity generation facility?

- 100% geothermal
- Access to fuel. I think someday diesel will become in short supply
- Adequate long term fuel supply at low cost.
- Again thermal electricity generation is outdate and not environmentally sensible!
- Again, not enough information for the public to have an opinion on this subject. What are the cost differences between fuel sources? Is reliability and maintainability comparable? What it the advantage of a dual fuel system? Why not just diesel? Too many questions, not enough information for the survey results to be useful. The public has no clue about this. Actually I don't know why the public opinion should affect the decision which is ultimately up to the utility to provide safe, reliable, and economical power supply. Too much consultation just adds confusion and slows down the process. YEC already knows the best technical and economical option. You have my support. Just stay away from more solar and wind PLEASE. That will only lead to more expensive and less reliable energy. The public doesn't get it. The emissions from the 10% of our energy coming from fuel sources for a population of 35k people are insignificant. We need reliable energy so we don't freeze in the dark.
- Air pollution.
- Air, ground water (fracking) and noise pollution
- All carbon based fuels are contributing to climate change which is now a dangerous situation. I don't support using any of these kind of fuels in a new facility

- Any type of fossil fuel use undermines our future, we need to use less, not more.
- Apparently, diesel is better suited to supporting the integration of renewables and avoids the fracking and methane emissions of LNG
- Availability of the fuel
- Availability, multiple suppliers to have competitive pricing
- Battery retention of renewables
- Be frank about who the real users and demand are - industry not residents
- Being forward thinking and look at what we have in the Yukon for natural resources we can use....
- Black start capability!
- Build adequate fuel containment infrastructure against spills. Build state of the art emission control facilities (off gas pollutants to comply with regulations).
- CLIMATE CHANGE. Where are the renewable resources?
- CLIMATE CRISIS.
- Capital investment and fuel costs need to factor into Yukon Energy's ability to adopt alternative sources of energy in the future. If fuels costs are low and capital investment high (such as LNG), we will likely not have the resources to adopt cleaner sources of energy in the future. Capital investment in diesel is lower and fuel costs are higher, keeping the financial incentive to use alternative renewable energy there.
- Carbon footprint
- Certainly not diesel. But please consider the source and its effect on our environment. Fracked gas is a danger to us all.
- Cheapest and most effective
- Clean
- Clean, efficiency, and productivity
- Clean, efficient and readily available.
- Cleanest but LNG
- Cleanest emissions.
- Climate Change. Those LNG plants are baseload, they are not appropriate for back-up, YEC deceived the Yukon people during the YUB and YESAB processes about how dispatchable LNG is. We need to stop burning fossil fuels, but because diesel is stable, can be ramped up to meet peaks and it works well with hydro, wind energy, and solar I will accept diesel. LNG is worse than coal when it comes to full life cycle GHG emissions. YEC can try to deceive the population about emissions, the low water levels, the hot fire season we are about to have, that YEC LNG plant has set in motion a carbon bomb, that our children's future is in jeopardy. Smarten up. YEC used to value Yukon people's opinion about diversifying our electrical grid, but ever since YTG got caught trying to privatize it back in 2008, and half the YEC board quit, YEC has just been a pawn of the oil industry. Mayo B was very expensive and it never worked the way YEC promised it would, now Mayo Lake is low. We need winter energy, and that is wind. Yukonners
- Climate change
- Climate change.
- Climate crisis
- Coercing us into such a choice is wrong and short-sighted
- Common sense if it exists?
- Compatibility with renewables.
- Consider scrapping this project and work with the Climate Change Secretariat and their integrated strategy team to come up with an â€insurance policy' that supports clean energy generation and a green economy.
- Consider the impact of GHC emissions and do not bring online any additional thermal/ combustion generation...
- Consider this as a very temporary solution

so that we move rapidly toward Renewable energy.

- Containment in the event of a spill (I support diesel despite this, as LNG does not store well and must be burned or lost). Therefore diesel complements renewables better than LNG due to its start-up, ramp-up and storage capabilities. Renewables must be accommodated as well as possible despite our need for fossil fuelled back-up.
- Cost
- Cost and availability to stable supply
- Cost of fuel. With dual fuel you have the flexibility to go with what's cheapest at the time
- Cost of generators
- Cost or availability
- Cost overall including initial infrastructure repair + maintenance + fuel
- Cost should not be the only factor and we should have batteries that store for power disruption not fossil fuels.
- Cost, safety
- Cost, then environmental implications
- Cost.
- Cost. Environmental friendly
- Cout et le plus ecologique
- Current & future price. Can we develop our own gas supply
- DO NOT USE FOSSIL FUELS.
- Diesel - rapid response on start up
- Diesel has lower capital costs and higher fuel costs. It should therefore be more easily replaced by renewable sources earlier and at a greater incentive.
- Diesel is a better choice than LNG because it has lower capital costs and higher fuel costs. Lower capital cost means more money for clean energy, and high fuel costs are an incentive for using renewable alternatives. LNG is harder to use with integration of future renewables.
- Diesel is better suited to supporting the integration of renewables and avoids the fracking and methane emissions of LNG
- Diesel is easy to store and also has a strategic importance. It can also be flown if needed. It starts fast and assumes the load immediately, it's safer to store in bulk.
- Do not build further dependence on any fossil fuels Invest in diverse renewable energy options and plan how to make it work through a smart grid
- Do not commit to buying generating facilities because that will hamper investment in future green energy options that may become available. Consider further demand side management to help reduce power requirements
- Do not use hydrocarbon fuels delivered on trucks to produce power here.
- Does one work better in the cold or is easier to have access to at all times?
- Don't build another facility that relies on fossil fuels. Invest in sustainable, renewable, green energy facilities: solar, wind, geothermal.
- Don't use fossil fuels.
- Don't use fossil fuels
- Duel fuel source please! I understand the desire for LNG, but using diesel means less trucks coming up the highway a long distance, and may local jobs.
- Ease of future integration of intermittent renewables.
- Ease of supply.
- Easy transport of fuel
- Economic efficiency.
- Effectiveness of facility
- Emissions
- Energy conversion from fuel to electricity to reduce truck travel on highways

- Environment
- Environmental impact
- Environmental impact and ghg emissions
- Environmentally friendly
- Exhaust output
- Existing supply inventory and support services.
- Expand on the backup systems at the mind sites
- Explore more of the possibilities of geothermal
- First, don't add any more thermal capacity unless it is biomass. The infrastructure you are suggesting will be with us for 20 to 40 years, do not build more petroleum based infrastructure.
- Flexibility, common sense and cost
- Fossil fuel free.
- Fossil fuels need to be phased out immediately. The Yukon has a lot of potential for micro hydro, wind and biomass all year round, and solar in summer. We also need to focus on consuming LESS electricity, as opposed to generating more.
- Fuel costs and emissions, hopefully having a dual fueled station will provide cost effective options, as long as the costs associated with building a dual
- fueled station makes sense.
- Fuel emissions and air quality for the surrounding areas.
- Fuel supply flexibility. That's why I prefer the dual fuel option.
- Fuel that can be easily used in other generating systems.
- Future of climate change! Be part of the solution not part of the problem.
- Future resources
- GHG emissions
- GHG's and the environment.
- Get off petro
- Go renewable, or get out.
- Green energy
- Greenhouse gas emissions from LNG are lower than diesel
- HEALTH
- Has there been any renewable energy explored and what were those results?
- Have you looked into Geo thermal solutions?
- How does it get here and what is the carbon footprint of these two comparatively? I want low emissions and lower environmental impact.
- How does the use of fossil fuels support Old Crow's climate emergency? I am very concerned that the territory is not concerned about its carbon footprint
- Hydro.
- I believe Yukon should move to Nuclear option, new systems are safe and reliable
- I do not agree with Yukon energy proceeding with this new facility. I believe there are better options for our community and this planet.
- I do not support anymore the use of diesel, dual-fuel, and LNG for power generation. The president and CEO, the vice-president and all senior management at Yukon Energy should be replaced, with leaders who can
- think outside of the box and listen to the public. The public are tired of dinosaur thinkers...
- I don't want fracking here, so I can't support it in other places
- I like to see the opportunity for our "insurance plan" to remain flexible so to me the obvious choice is for dual fuel. This will also allow us to maximize our financial investment maxing fuel choices depending on market prices.
- I prefer diesel over LNG because of its higher cost. I believe this will drive YEC towards using renewable alternatives. I have heard it

also lowers the initial capital cost.

- I support practical energy solutions. These are reliable. Solar and wind is unreliable. Storage is expensive. It is important to consider the overall economics and the cost to the consumer.
- I support renewable resources and am against long term investment on the reliance of fuel
- I want the Yukon to consider to only using this for emergency situations. Other plans should be created to plan for low water years, peak consumptions. I am disappointed that these options are not part of your plan.
- I want to see more information about the options considered and the costs of those options. You are not giving us enough information to make informed comments about this.
- I would like methane to be captured from the Whitehorse landfill and used to power the thermal plant.
- I would like you to generate electricity using chipped wood from fire smarted forests and recent burns.
- IT NEEDS TO BE RENEWABLE ENERGY
- If N60 is still supplying Diesel to the plant it's only a two hour drive out of Skagway. VS a two day drive from Vancouver or Edmonton. Diesel generators burn VERY cleanly now that they use DEF. Would be nice to see more Diesel gen sets then LNG. Plus LNG has to be fracked out of the ground... How honestly likes the idea of messing up someone else back yard to give us a little bit of power.
- If diesel or LNG has to be used, consider the option that is the less prone to GHG emissions from extraction to transportation to use.
- If it has to be thermal, make it geothermal.
- If the new station locates at the Landfill, consider the merit of developing an incineration generator with carbon capture technology for future power needs. If the station is locate at the Sewage lagoon investigate drawing thermal from the settling ponds.
- If you're going with petro-chemicals, please stick to diesel -- avoid fracking and water contamination.
- If, because of your mismanagement in the past, there is no way around fossil fuel powered electricity generation now, obviously, the type of fossil fuel with the smaller carbon footprint should be chosen: LNG
- Il serait bon d'explorer les avancees sur le plan de la production energetique en Islande et dans le nord du Japon (qui ont subi de trÃ¨s gros dommages dans l'accident nucleaire de 2011). Le Yukon se fie trop aux formules nord-americaines lorsqu'il s'agit de faire des choix.
- In a part of the world that is MOST effected by climate change, I'd like Yukon Energy to consider contribution to climate change/fossil fuel emissions in this choice.
- Integrate it into an energy use plan which more completely considers environmental effects here and where it's coming from and being mined.
- Investment and integration of renewable energy
- Is this for baseline or backup? If the latter, then diesel is more appropriate. Can this new massive investment firm up/allow for the addition of more intermittent renewables on the grid? It should.
- It is most important to me that a balance of the cleanest burning and reliability of the fuel source be taken into account as well as safety for the public.
- It must be renewable, and it is staring us all in the face. It is called our forests, and an ambition plan to create renewable fire-breaks will allow you to create a renewable plan for bio-fuels with sustainable harvesting for many generations (unless climate change does us in).

- It must not be fossil fuel of any type.
- It's a 20 year temporary plan to get us to a more economical and earth friendly option.
- I don't know the pros and cons of these choices - I wish you had given us more information we could base our choices on. My preference is whichever is least polluting (including lowest carbon emissions, though these are both fossil fuels).
- Keep carbon emissions to a minimum.
- Keep it simple! Complex machinery and controls are difficult to troubleshoot and service. Keep it simple!
- Keep looking at new technology as you move forward. There are more supporters than nay-sayers for LNG.
- Keeping cost effective and reliability in top priority
- Known significant problems with use of LNG even for a short term fix.
- L'impact environmentant
- LNG is cheaper and has lower emissions; design of the system should ideally find a way to make LNG-only work, because of these benefits
- Least particulates at point of use.
- Less noise, low impact, high yield. Education.
- LNG isn't ideal but pollutes a bit less than diesel
- Long term carbon footprint.
- Long term impact on environment
- Long term sustainability
- Longevity
- Longevity. Price and supply.
- Look at the total cost, including environmental effects.
- Look at wind or solar
- Low carbon footprint
- Low carbon footprint and clean exhaust.
- Low operating cost
- Low operating cost / compromise on capital cost.
- Lowest cost
- Maintain the lowest possible investment in fossil fuel power generation. We do not support LNG at all.
- Make a different decision entirely! Our planet is warming and the Canadian North is warming faster than anywhere else on the planet. We need to take real action now and adding more CO2 is not the answer!
- Make it renewable, or as a last resort, a facility that can be transformed to use renewable rather than fossil fuels.
- Minimal impact on carbon emissions, and minimal impact in resource extraction.
- Minimizing CO2 production.
- Minimizing greenhouse gas emissions.
- Moins de pollution et d'impact environmental global
- Most cost efficient and most intelligent for the future of the growing Yukon.
- Move towards non-fossil fuel based power generation
- Must be renewable!!
- My understanding of a hybrid system is quick startup. This would be beneficial.
- NO FOSSIL FUELS.
- NOT TO USE DIESEL OR LNG.
- No LNG
- No LNG, invest in renewable energy.
- No comments
- No fossil fuels
- No fossil fuels, please. Hydro, wind, solar, river, etc.
- No fossil fuels. No fracked gas. No GHG emissions. ONLY renewable energy.
- No fuel sourced from oil and gas extraction, the worst polluter there is, beginning with

the extraction process.

- Not burning more fossil fuels to provide electricity.
- Not coming from fracking sources (i.e. not LNG)
- Not to consider it at all. Plan for sustainable, dependable, clean hydro power generation.
- Our climate
- Our responsibility to future generations in supporting renewable energy options that have lower carbon emissions.
- Our social responsibility to create self-sustaining, renewable energy as a long term solution. None of the options listed give me the chance to give input towards sustainable energy.
- Planet
- Please consider more than the immediate future. Nuclear is the only sustainable way to survive as climate change marches forward.
- Please provide a Cost Benefit Analysis for all rate payers to review prior to making a final decision on any of the three options provided above.
- Please save the water and don't use fuels that require fracking.
- Please stop burning fossil fuels please look for cleaner energy sources
- Pollution
- Price. Cost implications for rate payers.
- Produce clean energy with readily available continuous supply of fuel
- Public safety
- REDUCE DEPENDENCY ON FOSSIL FUELS. We are in crisis mode, and it's not clear whether you have considered alternative options. If it's not feasible, explain why!!! And if it is feasible, you NEED to consider it.
- Rapid spin up, minimal use of LNG, potential to use existing infrastructure
- Reduce CO2 emissions and environmental risks associated with transport and storage.
- Reduce pollution & GHG
- Reliability and emissions
- Renewable
- Renewable PLEASE
- Renewable energy
- Renewable energy is a must.
- Renewable energy!
- Renewable or low emissions energy
- Renewable resources(solar energy, wind turbines)
- Renewable sources no more reliance on fossil fuels
- Renewable, non-fossil fuel.
- Renewables
- Renewables.
- Responsible and sustainable energy
- Risk for spills/storage issues
- Safe transportation and storage of fuel
- Safety
- Safety of the public
- Safety to the public and noise factors
- See above - Climate change and global warming are very real here in the north - we must look at alternative and renewable sources of energy that do not contribute to climate change and global warming,
- See above.
- See answer for Q2
- See past comment
- See previous reasons. Support DSM and more hydro
- Should be looking at pumped storage and solar for peak demand
- Since it should be "Emergency" use only or at peak hours, cheapest and most efficient fuel should be used. Diesel. LNG is Ecofriendly but in
- Whitehorse case we can handle it.
- Since the decision has already been made,

is it possible to have several smaller units so you can scale them up as needed, versus starting up the big old power plant? Natural gas would be preferred.

- Small Modular Reactors
- Smallest carbon footprint possible
- Solar or wind preferably.
- Solar, hydro, wind, geothermal
- Something with long term price stability and which can be transitioned/repurposed as other options come on line.
- Something, somehow, some way, that we can produce ourselves rather than truck up, and that does not involve further removing fossil fuels from the ground as we have been clearly told by top scientists and organizations around the world that in order for us to be able to have even a chance at mitigating climate change, we need to leave all remaining fossil fuels in the ground, and that we have only 11 years to turn our way of producing and consuming everything, including energy, around if our species would like to possibly survive.
- Stop using fossil fuels and start looking for renewable options
- Storage Safety
- Storage for power to be able to offer greener energy sources and a mass campaign for to empower reduced use and to implement peak power fees
- Storage of LNG, risk of stability of LNG and firefighting suppression of LNG all big considerations
- Straight diesel will probably be cheaper to maintain, more reliable and cost effective to operate than gas or dual fuel options. Probably be almost as clean as gas units, don't forget to factor in the gas gets trucked up here via diesel powered Kenworth, whereas diesel gets barged to Skagway and trucked only a short distance to Whitehorse.
- Supply line
- Sustainability
- THE ENVIRONMENT
- TO NOT USE FOSSIL FUELS
- TYPE OF FUEL DOESN'T MATTER, AS LONG AS FACILITY GETS BUILT.
- Tap a gas well a d keep it local.
- That Yukon and Whitehorse would work more towards decreasing fossil fuel use
- That fuel choice is made by people with a deep understanding of the technical and financial considerations, rather than the "average Yukoner" who may not have a sufficient understanding of the subject.
- That it be reduced at a later date via an uptick in the use of renewable energy sources.
- That it can be easily stored in the event of an emergency - in case we are cut off from the rest of Canada for some reason
- That it is a short term solution and more effort put into alternatives to fossil fuels
- That it is a short-term solution, with the view to incorporate wind and solar energy and viable energy producers.
- That it is renewable. Personally I prefer fusion from the sun- either solar PV or Wind, backed up with lavish supplies of batteries and a couple of pumped storage facilities.
- That it's green and renewable, which neither diesel nor LNG are.
- That you ask the advice of climate change scientists and find solutions that are thinking ahead 7 generations and fir the earth. Use wind or solar or water that doesn't require more dams.
- The LNG is not from a fracking source as we do not need any more earthquakes "man made" as we are doing enough harm to mother earth already
- The ability to use different fuels
- The cheapest and most efficient type of fuel.
- The dual fuel approach (engines that can

burn either diesel or LNG) provides flexibility, and should be a serious consideration, if there is little or no impact on engine efficiency.

- The environment
- The environment.
- The environment. No fracking, no fuel emissions, no carbon footprint
- The environmental impact!
- The fact that YE is far behind in its thinking and acting on investment in renewable energy. NOW is the time - not later. NO NEW INVESTMENTS in FOSSIL FUELS!! Do not give people choices between various planet destroying fuels. Instead, help them to install renewable energy in their homes and workplaces.
- The filthy and environmentally harmful nature of fracked natural gas should preclude it from further consideration as a fuel source.
- The future. Diesel and LNG are not the future.
- The impact that it will have on habitats and wildlife
- The lowest cost possible. This facility is not meant to be used all the time - it is for backup only.
- The most clean type of fuel please.
- The most important consideration is the long term impact on Yukon Energy's ability to integrate renewable energy sources. Diesel is vastly preferable to LNG in this case due to lower capital costs and higher fuel costs. The higher fuel cost provides a stronger financial incentive to rely on clean alternatives and the lower capital costs leave dollars available for investment in clean energy.
- The option of conversion to renewable energy sources.
- There MUST be other options considered. LNG is coming from where? It's not a smart choice.
- They should consider that adding a fossil fuel based plant is regressive.
- Think outside the box. Consider green initiatives for sustainable energy sources.
- This is Yukon Energy's chance to become a world leader in developing renewable energy sources in the north. We are already seeing the effects of climate change at a rate far greater than in the south. Please do the responsible thing consider alternative "green" sources of energy. I DO NOT
- SUPPORT THE CONSTRUCTION AND USE OF ANOTHER THERMAL GENERATING SYSTEM.
- This is choosing the lesser of two evils. Diesel is preferable to LNG because it is less of a long-term commitment to fossil fuels, at a time when the world needs to be rapidly moving to clean energy sources. Yukon Energy should prioritize demand side management, renewable energy and clean energy storage over fossil fuels, but if investments in fossil fuels are unavoidable then Yukon Energy should opt for diesel.
- This survey is not giving Yukoners a "choice". It's like asking us to choose the colour of the car, not the engine.
- Total carbon footprint.
- Transitioning to green energy down the road. Need petroleum products for now but need to keep adding green technology to the system.
- Two better than 1 in an emergency
- Until we have a local gas pipeline choose diesel. Easier storage and handling also many more options for local diesel suppliers.
- Use LNG less carbon
- Use Yukon LNG
- Use a fuel source that has the lowest emissions but can handle our climate
- Use a renewable resource.
- Use a renewable resource. (Wind, geothermal, etc...)
- Use renewables

- Use solar and wind use renewable energy that does not pollute.
- Useless question
- We need more hydro power
- We need renewable energy solutions NOW.
- We need to address long term power supplies not relying on oil and gas. We need to travel two roads, as it were - using LNG/ diesel while developing wind, solar.
- We should be using these fuels. This is outdated thinking and expensive.
- Invest in cheaper more sustainable generation facilities.
- We should move to renewable power sources.
- We should not be investing in fossil fuel powered infrastructure in 2019. The increasing power needs and impacts of climate change on the capacity of the Whitehorse dam should have been predicted and action taken earlier. Given it has apparently come to this, the temporary addition of diesel generator capacity is the least worst option.
- What is the environmental cost?
- What the waste products are doing to the environment
- What works best for a long term growth
- Whichever has the lowest greenhouse gas emissions, and can be most easily pulled from service once renewables become broadly employed.
- Whichever one moves us towards a green energy future
- While it is too bad that some cleaner energy solutions (wind & solar for example) are not necessarily feasible for various reasons I think it is important that whatever system is put in will be as "clean" as possible.
- Why are we using thermal electricity? "The environmental benefits of heating with highly-efficient biomass wood-chip boilers over traditional fossil-fuel boilers are without a doubt self-evident (higher efficiency, waste-utilization, GHG reduction, etc.). But what is uniquely important about this project in the Teslin region is the community danger currently posed by the extremely high fire-risk assessment that was always known but recently confirmed by UNBC researcher in 2014. The forest surrounding the community has not experienced any significant forest fires in over a hundred years, resulting in significant over-growth and a serious potential for out-of-control burns in the future. With this understanding, our community will undertake brushing, fire-smarting, and other sustainable selective-harvesting methods that will assist with both objectives of supplying biomass feedstock and the enhancement of the forest ecosystem surrounding our community and throughout our traditional territory."
- Will it harm the environment? We're on fire, folks!
- Wind generation, and not locating any new generators in the downtown (river valley)
- Zero greenhouse gas emissions!
- again, safety of people, protection of surrounding environment, keep noise pollution down, keep air pollution down,
- availability and reduced emissions
- Availability of fuel, how far will it have to be transported, how safe is the transportation.
- clean energy
- cleaner energy
- climate change
- cost
- cost and dependability of supply
- cost and effect on environment
- cost and supply
- cost to consumer
- costs
- ditto
- do not build this facility

- do not support fuels sourced through fracking
- efficiency
- greenhouse gas
- greenhouse gas emissions / long term environmental impact
- important in an emergency to be responsive in providing power so there are no 'disasters' in cold weather
- It has to be 100% renewable combined with battery storage.
- It is sustainable...biomass can be...LNG and diesel are not.
- it should be a renewable resource--solar, wind, water
- it would have to be environmentally friendly
- just don't build it
- keep the grid up, prevent brown outs and outages
- local availability
- low carbon emissions
- Lowest carbon footprint.
- lowest cost
- lowest cost and highest stability of pricing
- making sure it is temporary
- Minimal impact on climate change - LNG is bad because it has serious impacts on the earth when it is mined/removed.
- n/a
- No thermal facility at all. Dust off your old studies and put them to use for renewables.
- nuclear
- operational certainty----- like availability, ease of startup, cold weather reliability
- pollution
- potential impact to environment and people's health and safety in the event of an accident (e.g.: spill)
- price
- Projected fuel costs, availability and environmental impact of a worst case scenario spill. There is not much that Yukoner's value more than environmental health of our waterways and the public would likely be willing to pay more for added security.
- reliability
- reliable supply
- Renewables!
- safety and reliable source to provide fuel
- safety in storage of volumes to meet beyond normal anticipated consumption
- Simplicity: it's an "insurance plan". Keep it simple and reliable.
- spin up time utilization of fuel when needed i.e. problem with boil off
- Sustainable and renewable sources. Geothermal?? More turbines?
- that the fuel source is better suited to supporting the integration of renewables (basically not encourage fuel sources that will just lead to more greenhouse gas emissions like LNG)
- the most cost efficient
- Ultimately, the consumer will pay for whatever fuel the new facility will use, so I would say the most cheaply way we can get power :)
- use fuel from eagle plains
- which has lowest greenhouse gas emissions end of day, including cost of transport to yxy
- Energie renouvelable (bois, geothermique)

Q7. Do you recall seeing an information brochure from Yukon Energy regarding new thermal powered electrical generation?

	Frequency	Percent
Yes	159	35.57
No	259	57.94
Not sure	29	6.49

Q8. If you recall seeing an information brochure on new thermal powered electricity generation, how helpful was it in informing you about site location and fuel source options?

	Frequency	Percent
Not very helpful	23	14.47
Somewhat helpful	74	46.54
Very helpful	44	27.67
Not sure / No opinion	18	11.32

Q9. Did you attend an Open House hosted by Yukon Energy regarding new thermal powered electrical generation?

	Frequency	Percent
Yes	44	9.84
No	392	87.7
Not sure	11	2.46

Q10. If you attended an Open House on new thermal powered electricity generation, how helpful was it in informing you about site location and fuel source options?

	Frequency	Percent
Not sure / No opinion	2	4.55
Not very helpful	4	9.09
Somewhat helpful	13	29.55
Very helpful	25	56.82

Q11. Do you agree or disagree with the following statements:

a. Yukon Energy values and respects public input.

	Frequency	Percent
Strongly disagree	68	15.21
Somewhat disagree	93	20.81
Neutral / No opinion	136	30.43
Somewhat agree	106	23.71
Strongly agree	44	9.84

b. I know how to provide input into Yukon Energy.

	Frequency	Percent
Strongly disagree	25	5.59
Somewhat disagree	87	19.46
Neutral / No opinion	90	20.13
Somewhat agree	175	39.15
Strongly agree	68	15.21
Not answered	2	0.45

c. I know how to access information about Yukon Energy to provide informed input.

	Frequency	Percent
Strongly disagree	23	5.15
Somewhat disagree	78	17.45
Neutral / No opinion	83	18.57
Somewhat agree	182	40.72
Strongly agree	78	17.45
Not answered	3	0.67

d. Yukon Energy works in the best interests of Yukon residents.

	Frequency	Percent
Strongly disagree	82	18.34
Somewhat disagree	108	24.16
Neutral / No opinion	96	21.48
Somewhat agree	97	21.7

Q12. In which community is your primary residence?

	Frequency	Percent
Dawson City	14	3.13
Marsh Lake	9	2.01
Other Yukon	17	3.8
Whitehorse area (including Mount Lorne, Lake Laberge)	407	91.05

Q13. Are you a member or citizen of a Yukon First Nation or a transboundary First Nation (British Columbia, Northwest Territories)?

	Frequency	Percent
Yes	10	2.24
No	387	86.58
Prefer not to say	50	11.19

Q14. What is your age?

	Frequency	Percent
18 or under	5	1.12
19-29	26	5.82
30-39	108	24.16
40-49	88	19.69
50-59	95	21.25
60-69	96	21.48
70 or over	29	6.49

Q15. What is your gender?

	Frequency	Percent
Male	243	54.36
Female	139	31.1
Gender diverse or non-binary	3	0.67
Prefer not to say	62	13.87

Q16. How long have you been a Yukon resident?

	Frequency	Percent
Less than 1 year	4	0.89
1 to 5 years	38	8.5
6 to 10 years	54	12.08
11 to 15 years	39	8.72
16 to 20 years	43	9.62
More than 20 years	269	60.18

appendix d: emails, letters and phone calls

May 27 – July 15, 2019

Some comments have been summarized due to length

Participant comment/question	Yukon Energy Response
I'm concerned with the company's use of more fossil fuels. I want to see more renewables, particularly wind developed.	Not available to provide response as no name or phone numbers was left with voice mail.
I don't understand why you would invest in fossil fuels when that technology seems outdated. You should be looking at technologies and examples being used outside of Canada.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
We need to urgently move away from fossil fuels both for political and environmental reasons. There are other alternatives that you should explore including hydro, generating hydrogen, using plastic garbage to generate power, and thorium generators.	Thank you for your feedback. These comments will be considered as part of our project recommendation. We also appreciate the other examples of power generation you shared with us. This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.
We feel that the new facility should avoid the proximity of existing LNG and diesel infrastructure. We also don't want to see this beside residents as it is capable of introducing large amounts of airborne emissions. It would be unwise to locate back-up generate near the airport or Schwatka Lake. We are indifferent to the fuel you choose. We propose you build this near the Takhini substation.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
What about biomass and geothermal for base load energy? Solar can fill the gap in March, April, May and June. What about wind? Yukon Energy never foresaw the transition of homes to electric heat. I don't see evidence of Yukon Energy trying to aspire to anything new. Your thinking is outdated. Customers and businesses like me want more renewables. Don't try to convince me that LNG or diesel is the solution. I am disappointed in Yukon Energy.	Thank you for your feedback. These comments will be considered as part of our project recommendation. Thank you for your views on other electricity sources we should be exploring. We explored each of these possible options in our 2016 Resource Plan. As part of that plan, we also considered the increased use of electric heat and vehicles in Yukon. This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.

I'm disappointed to see Yukon Energy deploy more thermal energy without equal progress and investment in renewable energy projects. Of the options provided, I strongly prefer diesel to LNG as diesel is better suited to supporting the integration of renewables and avoids fracking and methane emissions. I strongly also prefer rental generator to purchased units to minimize Yukon's investment in fossil fuels. I implore Yukon Energy to begin deploying conservation and renewable energy projects needed to achieve territory-wide GHG reductions consistent with the Intergovernmental Panel on Climate Change on limiting global heating and the need to reduce GHGs by 50% by 2030 and 100% by 2050.	Thank you for your feedback. These comments will be considered as part of our project recommendation. Like many Yukoners, we are proud that more than 90% of the electricity generated in Yukon comes from hydro. We are exploring this project because we need to ensure the availability of safe, sustainable, reliable and affordable power to Yukoners. This project is one of many we are pursuing to meet current and future demands for electricity including a grid-scale battery, two small hydro developments, enhancements to our hydro storage capabilities, upgrades to our existing Whitehorse hydro facilities and energy conservation programs.
Investing in this type of infrastructure is a shame and I'm honestly disappointed. I feel real questions would have occurred many years ago to have had proper planning, not a stop gap new energy source; looked at a variety of energy sources and how a combination of them would work to meet the need; how we can continue to reduce our need with creative solutions like peak and off peak power. In encourage you to think bigger and better.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
I believe Yukon Energy should have a greater reserve or buffer of renewable energy capability to cover droughts, load growth and other risks Yukon Energy presently has. Exactly is open to discussion, but I suggest at least 10% of the anticipated annual load as starting point; a good portion could be sold into secondary sales). There is no diversity in Yukon Energy's renewable energy supply; it is essentially all hydro. In my view winter dominant wind energy should compromise at least 10% of Yukon's electricity supply. I consider LNG and diesel as equally polluting and contrary to any meaningful action to mitigate climate change. For the short term, I prefer the use of dual fuel generators in P126 (diesel plant retrofit) and diesel everywhere else. We must prepare for more intermittent renewable energy use on the grid, especially wind, but other forms too, and for that (and outage restoration) higher ramp rates for load following are key and only diesel can do the job. If there were no debt cap restriction on Yukon Energy my preference would be for Yukon Energy to install dual fuel generators in the existing Whitehorse diesel plant. I would also like to see the Faro diesel plant and associated infrastructure continue to be fully utilized. With P126 and Faro full utilized, I believe Takhini	Thank you for your feedback. These comments will be considered as part of our project recommendation.

switchyard / substation is the next best location. This site should be designed to be expandable to accommodate future growth. In my mind it would also reduce the risk on the grid to have some generation supply on the north side of this facility (instead of all at Whitehorse Rapids). But what about Dawson and Mayo City too? If Yukon government debt cap is an issue, YG should do whatever they can so that he debt cap is not a constraining issue on Yukon Energy. Number 1 choice would be to put diesel units outside P126 and then build a facility for rental diesel units at the Takhini switchyard/substation, minimizing Yukon Energy's capital costs so that available capital can be allocated to new renewable energy supplies. A second close would be the Whitehorse landfill; my next option (though distant) would be the Lagoon	
Email to YG. I am deeply concerned about the proposed Yukon Energy Thermal Plant. It is irresponsible of our government to continue investing in fossil fuel energy when our communities face a climate crisis. Why isn't the government investing in renewable energy? If we are encouraging more ownership of electric vehicles and more electric home heating, then shouldn't we also ensure that the electricity they draw from comes from a clean source? The changing climate could also mean the Yukon Energy's hydroelectric projects aren't reliably able to provide as much energy as needed. We need to invest in other renewable energy projects. There is a demand for more energy now, and this is the ideal moment to take firm action on climate change	Response provided by YG
Email to YG. I understand the reluctance to rent diesel generators for years. But I don't believe that investing in a new diesel/LNG generator is the wisest choice. I'm sure Yukon Energy has been careful in their study of Yukon's energy needs. It is only human to have a preference for known solutions and practices, however this looks like a case of only having a hammer so everything looks like a nail. As Kate White pointed out at the June 10th Yukoners Concerned Meeting, the high cost of a diesel/LNG electric generator will make serious investment in renewables impossible and will lock us into fossil fuels for a generation. Given our climate change crisis, this is not the time to go with what is seen too be tried and true. Renting diesel generators will give us the time we need to develop alternative energy sources, Perhaps we will have to frack to find out if	Response provided by YG

geothermal is a good answer for the Whitehorse basin.	
I am 100% against LNG and Diesel and would rather have long power outages or rotating power rather than have his electricity generated by fossil fuels. I feel that both of these options are environmental disasters and we should be looking at creative hydro alternatives (i.e. Hydro with a pump to run water through the unit multiple times). I also feel like the term "Thermal" used in our media campaigns was deliberate political misspeak and that it was done intentionally to throw off the public because when people hear "thermal" they automatically think "geothermal".	Response provided by YG
I would like to register my utter disagreement with Yukon Energy's proposed approach. I do not want to see any further non-renewable energy development in Yukon. In addition, more particulates expelled into our valley are not preferred. I want Yukon Energy to continue to rent diesel generators as backup until wind, solar and geothermal energy sources are developed to cover the current and future energy needs of Yukon. In addition, I want to see a plan to phase out use of the current diesel and natural gas generating capacity... keeping the natural gas or diesel for backup.	Thank you for your feedback. These comments will be considered as part of our project recommendation.
Yukon Conservation Society provides this feedback as a member of the Technical Advisory Committee and an organization representing a membership of approximately 300 Yukoners. We are of the view that Yukon Energy and Yukon government need to collaborate to grow Yukon's renewable energy capacity and enable GHG emissions reductions in Yukon's heating and transportation sectors. Major investments in fossil fuels is counterproductive to meeting the science based GHG emissions targets required to avoid the worst effects of global heating. YCS's specific comments are as follows (the following is paraphrased by the transcriber for length). 1. Alternative solutions have not been adequately considered. The combined use of Demand-Side Management (DSM) and Electric Thermal Storage (ETS) can reduce peaks loads by up to 16 MW Further capacity-focused programs such as hot water tanks timers, thermostat set back and time of use electricity pricing can drive significant further reductions. DSM programs would reduce the number	Thank you for your feedback. These comments will be considered as part of our project recommendation.

of rental generators required over time, resulting in long-term financial savings and positive socioenvironmental outcomes. 2. Yukon Energy has not assessed the impact of the proposed options on the avoided costs of thermal, the metric used to set prices for the Independent Power Producer Policy. This metric drives the financial viability for all potential IPPS. Ignoring this metric could have significant long-term adverse impact on the effectiveness of the IPP policy. 3. Yukon Energy has not assessed the impact of the proposed options on Yukon Government debt cap, which directly impacts Yukon Energy's ability to develop renewable energy projects in the future. It is critical that the debt ca implications of each option (rent/own) be assessed to understand the future impact on the corporation's ability to invest in clean energy infrastructure and ambitious DSM programming. 4. Having considered the issues above, the Yukon Conversation Society is of the view that diesel generators are the preferred solutions. Key reasons are as follows: • Diesel avoids the hydraulic fracturing and methane emissions associated with LNG extraction and transport. • Operational characteristics of diesel generators make them better suited to the integration of intermittent renewable energy sources. • The generators, fuel storage, and other infrastructure costs are lower for diesel systems, resulting in lower capital investment in fossil fuel energy and more capital available for clean energy alternatives. • The lower capital cost of a rental facility results in more capital available for clean alternatives. • The flexible nature of generator rentals results in a significant financial incentive for Yukon Energy to reduce reliance by investing in clean electric capacity alternatives such as DSM and energy storage. Since the "avoided cost of thermal" metric is based solely on fuel costs, the use of diesel rather than LNG will result in better economics for Independent Power Producers.	

Dear Mr. Hall, Please accept these written comments as the Yukon NOP Caucus response to the New Thermal Generation Project. General Comments: While we were disappointed to hear that the Yukon Energy Corporation would be beginning the construction of a new Thermal Generation Plant, we recognize the realities Yukon faces when it comes to power generation. Our comments are not meant to call into question the need for more electrical generating capacity to address emergency scenarios, baseload and peak winter load, nor are they intended to call into question the commitment Yukon Energy has made towards moving towards greener energy production infrastructure. Rather they are rooted in our belief that the Yukon, and the planet as a whole, need to take swift action to transition away from fossil fuels, if we hope to meet the IPCC target of 50% GHG reductions by 2030 to limit the extreme effects of climate change. We believe that Yukon Energy's proposal to invest in a long term, permanent thermal generating facility is short sighted and will harm Yukon's ability to meet critical emissions reductions targets and harm our ability to easily switch to renewable generation technologies. Rent vs. Own: It is the firm belief of the Yukon NDP that the Yukon Energy Corporation should rent thermal generators, rather than construct a permanent thermal generation facility. We believe that tying Yukon's energy future to fossil fuels for the next 40 years is counterproductive and short-sighted. This long term investment will inhibit the Yukon from effectively transitioning to a GHG emissions free energy infrastructure. This proposal of a long term investments in thermal generation is a line in the sand for the Yukon NDP. We have faith that good decision making, planning and advancements in technology can get us to a greener future. After a lively discussion at one of the YEC open houses on the new thermal generation plant options, we believe that renting the required generators needed is the answer. One of the YEC representatives present suggested that if generator rental was the direction chosen, that option should be coupled with the purchase of the necessary supporting infrastructure (including transformers, fuel tanks and cables). We agree. The Yukon NOP is supportive of any options that gives the Yukon the ability to more easily decommission this proposed thermal generation plant as we transition towards renewable options. It is our hope that renting	Thank you for your feedback. These comments will be considered as part of our project recommendation.

generators in the short term would allow Yukon Energy to take the steps necessary to establish renewable alternatives to fossil fuels. LNG vs. Diesel: The Yukon NOP fundamentally disagree with the practice of hydraulic fracturing within our borders, if this isn't acceptable in Yukon, then we shouldn't think it acceptable elsewhere. Therefore, the Yukon NOP is opposed to any new investments in LNG infrastructure. The Yukon NOP is also concerned about the impact that building more LNG generating capacity could have on Yukon's renewable energy future. Currently the IPP policy's avoided cost of a blend of diesel and LNG is approximately 16 cents a kilowatt hour. It is our understanding that prior to the installation of the LNG generators in 2015, Yukon's avoided cost of fuel was to be approximately 28 cents a kilowatt hour. While LNG has some cost and GHG benefits, we believe that its introduction into the Yukon has created a situation in which renewables have and will continue to struggle to gain traction. It is our opinion that further LNG investments have to potential to keep the IPP purchase rates low and therefore harm the ability of renewables to compete. It we need to use fossil fuels, diesel is our only choice. Location: It is the opinion of the Yukon NDP Caucus that, based on a reading and discussions of the potential site options, situating the new thermal generating plant at the Whitehorse Landfill would be the ideal location. We would also advise you to consult with the City of Whitehorse to consider the implications the project may have to the City OCP. This site would easily allow for the use of biomass as a heating source for the rental generators. Sincerely, MLA Takhini-Kopper King	
Email to YG. Please find below a copy of Yukoners Concerned May 28/19 Newsletter. Yukoners Concerned is shocked by Yukon Energy's plan to build another permanent thermal generation facility in the Whitehorse area. We accept the fact that we need thermal backup energy but we are now moving into Load production. This means the Yukon will see very little major renewable energy for the next 30 years. During the past 10 years Yukon Energy and the Governments of the day have held workshops on alternative energy and with rapid Climate Change the need to get off Fossil fuels is a must to save our environment for future generations. A major concern around thermal generation especially the burning of LNG is the safety of the sites as well, as the	Response provided by YG

transportation, and the impact of air quality in the area. Our government Leaders have not understood that Climate Change is a reality, and World experts state that we have only 10 years left to change the catastrophic results of doing nothing? If we need more back up then we should rent the units rather than build and maintain them and get on with a major Wind, Solar, Biomass etc., and generation facility. Before the last Territorial election over 8000 Yukoners signed a petition to ban LNG to generate electricity. Once again Yukoners must be heard by the politicians and do the right thing. Yukoners Concerned.	
Email to YG. Re: Consultation on Thermal Generation Facility I am writing you today to request that you extend the consultations for your government's proposed 20 megawatt thermal generation facility. The Official Opposition has heard concerns from many Yukoners regarding the very short and limited ability to be properly consulted on your government's proposals. The majority of the concerns that we have heard relate to the short length of the consultations, the short notice for the open houses, and the fact that rural Yukon was completely left out of the open house portion of the consultation process. As you know, during the summer Yukoners are very busy either with work or personal matters and are not necessarily checking EngageYukon.ca on a daily basis to see if there are any open or planned consultations on significant matters. Further, Yukoners require and deserve an adequate length of time to be notified that a consultation is taking place so that they can make the necessary plans and adjustments to their schedule which would allow them to participate. Notification for the open houses only began on May 21st, with the first open house taking place on June 1st and the final open house taking place on June 6th. That is only a total of 13 business days from the beginning of the consultation to the conclusion of the consultation and we do not believe that can be considered meaningful engagement. In fact, we have heard from many Yukoners who were not even aware that there were open houses taking place until after they had concluded. Finally, all four of the open houses were held in Whitehorse only. Any decision on Yukon's energy future will have short-term and long-term impacts on all Yukoners, not just those who live in the city, so in the interest of fairness, all communities	Response provided by YG

deserve to have their voices, concerns, and questions heard as well. These impacts go beyond simply the location or source of energy, but also the budgetary impacts that a multi-million dollar investment would have on the government's debt or deficit. As such, the Yukon Party Official Opposition is requesting that your government extend the consultations and open houses on this important topic to ensure that all Yukoners are able to be heard. I understand that the Yukon Chamber of Commerce previously wrote your government suggesting a 30 day standard for consultations, and I believe this would be a fair length of consultation in this instance. Finally I would request that you host an open house regarding this proposal in all Yukon communities to ensure all Yukoners are able to participate. Thank you for your consideration in this matter. Sincerely, Official Opposition Critic for Yukon Energy Corporation	

appendix e: social media

May 27-June 14, 2019

Participant comment/question	Yukon Energy Response
Confused as to the thermal part of this. You're just offering diesel or gas	Yes, at this point we are proposing the development of a new permanent LNG, diesel or dual-fuel (runs on both) facility.
So then why try and brand it as a thermal solution, why not be honest with Yukoners?	No response posted.
What about solar, geothermal, wind, biomass? Like the youth are saying, "you die of old age, we die of climate change."	Solar, wind, geothermal, biomass and other renewable projects were all explored as possible options to help meet our need for more dependable power supply when we worked on our 2016 Resource Plan. These options were ruled out of the portfolio of resources we're on now for two reasons: first, these sources of renewable power don't provide the dependable electricity supply we need during winter months; second, these resources were too expensive to build at the scale we needed them to be. The portfolio of resources we're pursuing now (new small hydro, hydro storage enhancements, hydro upgrades, new battery, new LNG or diesel, and connecting Independent Power Producers) meets our need for dependable winter supply in the most cost-effective way. Here's a link to our 2016 Resource Plan.
No it's time we diversify our sources! We have highly qualified people in our community to help do so! Why are they not part of the process?	We agree, we need a mix of energy sources available to ensure we can continue to deliver safe, reliable and affordable power. We also agree that the Yukon is rich with energy experts. That's why we're talking to a number of different local groups, experts and stakeholders about this project to collect theirs views and perspectives.
Why thermal? What happened to the plan building a new hydro dam? Yes this would have a larger footprint. But hydro is a reliable renewable energy we have right here in the Yukon!	The proposed new thermal facility is needed to help keep the lights on during emergencies and low water cycles, and when the demand for power is larger than what we can meet with our hydro power. We are also exploring ways to bring more renewables onto the grid including two small-scale hydro developments, a grid scale battery, hydro storage enhancements, and upgrades at our Whitehorse hydro facilities.
That is what we were told about LNG too. There has been ample time to move to renewables between that very unwise investment in LNG infrastructure and now. Any additional source of energy for the Yukon will take time to install. Use renewables NOW.	No response posted.

Nothing will be an immediate "emergency" source of power. Stop trying to scare people into accepting more investment in fossil fuels.	
Yes go to natural gas	No response posted.
Canada is considering declaring a Climate Emergency, the west is choking and people are dying from fires, the east is flooding and the north is affected by Climate Change more than most of the rest of the world. What are you considering?	We're committed to making the most of the renewable resources we already have (primarily hydro), and building and integrating more onto the grid. We're exploring two possible new hydro developments, the installation of a grid-scale battery, as well as enhancing our storage capabilities in our Whitehorse and Mayo reservoirs. We also working with a number of Independent Power Producers to help them integrate the renewables they are building onto our system. More information about the portfolio of projects we're looking at is available here.
If you fill up the survey. Just remember that it is a conducive questionnaire where they just get the answers that they want. So remember in the comments that you can suggest a more clean energy.	No response posted.
Yukoners! There are options given in this survey... but maybe there are non-fossil fuel based options that aren't mentioned? Whatever you think, if you have the time and inclination, please fill out this survey!	Comment included as part of a shared post. No response posted.
Get off the fossil fuels. The Yukon has an abundance of geothermal energy just waiting to be tapped into. http://www.energy.gov.yk.ca/geothermal.html These reports date back to 2016, what is being done by Yukon energy to pursue geothermal energy?	We explored geothermal technology as part of our 2016 Resource Plan. Two possible sites were identified, however those projects were not pursued because they were not found to be in the most cost-effective portfolio of resources needed to meet the increased demands for electricity.
Do you ever come out of Whitehorse for these meetings?	Thanks for your question. For these types of projects we typically host open houses in communities where the proposed facility may be located. In this case, because the five proposed locations are in or very close to Whitehorse, our open houses will be in Whitehorse. We certainly want to hear the views and opinions of residents living outside of Whitehorse on this project too. To help facilitate that there is an online survey that anyone can take to let us know what they think about the project. Here's a link.
If it involves more fossil fuels, keep thinking	No response posted.
Is there a future for those disabled windmills on Haeckel Hill? It cost a small fortune for the study to decide the best place to put them and again to replace a worn out bearing. They were supposed to be enough to power 300 houses but the power they did generate just went back into the energy grid so there was no visible end use we could all appreciate. We	The Haeckel Hill wind project Michael linked to is a great example of the opportunities available through the Yukon Government's Independent Power Production policy. https://yukon.ca/.../government-yukons-independent-power... We're excited to work with this and future

could have a greenhouse complex up there they plug into in which many of us could be happily employed growing essential nutrients cutting some of the shipping requirements to get food here from parts south. We could add more windmills and some solar collectors besides. We could also take advantage of river current for some energy too.	proponents to integrate more renewables into our isolated grid as we continue to work on building more renewables ourselves. This proposed New Thermal generation facility will help us ensure the availability of reliable power when existing and future renewables aren't available
When does the online survey close?	June 9.
I recognize the need and have contributed my views on new reliable thermal, but as a point of reference, what would $50m in renewable investment get us? Asking for most Yukoners	The cost of renewables depends on the type, location, size, distance to grid, etc. For dependable capacity, we'd likely get less than 5 MW of hydro for $50M in comparison to the 20 MW we are designing for about the same price for thermal. The other big difference is that to build hydro often takes at least 5-7 years. We expect this LNG/Diesel/Dual-Fuel facility can be ready in about 3.5 yrs. This helps us meet growing demand sooner. 2/2
Good stuff, thanks. This is important for having the public understand the why, and to communicate that you know how the renewable option compares. Worth getting that message out alongside this.	No response posted.
Where on earth did you get the social license to not make developing our renewable resources a priority? The 2016 Resource Plan is a flawed document. We need winter renewable energy and storage that means wind and electrical thermal storage and a smart grid. Please modernize your approach YEC.	No response posted.

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October 2019



ISSUE: **EPA constraints**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "The effect on customer rates of energy and capacity purchases under the EPA is constrained by the agreed price and payment terms (see Section 2.4.3 of this Submission) and the actual dependable capacity and delivered energy provided by THELP."

QUESTION:

a) Please explain the above quote and why the statement is accurate in terms of the effect on customer rates.

ANSWER:

(a)

The above quote incorrectly references Section 2.4.3 of the Submission (which does not exist) – the relevant reference is Section 3.4.2 of the Submission (see also response to YUB-YEC-1-40).

The referenced quote from Section 4.2 is an introduction to review of EPA effects on customer rates. In summary, the quote states that effects on customer rates from YEC's Atlin EPA purchases (of energy and capacity) is determined by two main factors:

- The EPA price and payment terms (which are summarized in Section 3.4.2 of the Submission); and

- The actual volumes of dependable capacity and delivered energy provided by THELP.

The statement accurately summarizes the factors determining EPA annual total impacts on YEC's costs. Further, review of EPA price and payment terms highlight that these have been determined based on forecast YEC costs for thermal generation options that are assumed (for EPA pricing) to be otherwise required, i.e., the net cost impact on customer rates is mainly determined by the EPA price and payment terms to the extent that costs

with the EPA are basically the same as (and in some situations lower than) would otherwise occur without the EPA.

The subsequent text in Section 4.2 after the referenced quote addresses in more detail the price and payment provisions for Dependable Capacity, Winter Delivered Energy, and Summer Delivered Energy and the likely EPA net impacts on customer rates. This text highlights the importance of the EPA commercial terms and factors that may impact final net impacts on customer rates. In addition, a third factor is in effect identified as affecting net customer rate impacts, i.e., the actual (vs the forecasts used to set EPA prices) thermal fuel costs and grid conditions regarding loads and other renewable resources.

ISSUE: **Costs for dependable capacity**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "EPA impacts on YEC costs for dependable capacity and delivered energy are designed to mirror or improve upon the cost impacts on YEC and customer rates forecast for a permanent thermal generation option"

QUESTION:

a) Why is a permanent thermal generation option the standard by which these costs (Dependable Capacity Payment and Winter Delivered Energy) are measured?

b) Should not the costs for dependable capacity be measured under the EPA on whether those costs are less than a thermal generation option? If no, why not?

ANSWER:

(a)

The permanent thermal option was adopted as the benchmark for costs on the assumption:

(a) That thermal generation in general is the least cost option for both dependable capacity and winter energy (for energy, this enables reference to the blend of LNG and diesel thermal generation); and

(b) That permanent thermal (diesel) is the preferred thermal long-term option (compared to diesel rentals) given the challenges and reliability risks of adopting rented diesels on an ongoing basis for the next several decades.

Please also see response to YUB-YEC-1-7(a), which also highlights the focus on selecting renewable generation options.

(b)

No. As reviewed in the response to YUB-YEC-1-7(a), the clear public policy need is to develop where feasible the renewable generation options. Accordingly, renewable options such as the Atlin EPA are very attractive if they are simply cost competitive with thermal generation options. Under the Atlin EPA, YEC therefore sought a renewable option that was cost competitive with permanent thermal. Under the EPA, under some circumstances the EPA will also be less costly than thermal generation.

ISSUE: **Dependable Capacity Payment**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "Dependable Capacity Payment (DCP): the DCP payment to THELP by YEC in the EPA is based only on the Dependable Plant Capacity Committed (DPCC) as confirmed by an annual December test as provided for in Section 5.5 of the EPA, and a Dependable Capacity Price of $200/kW per year (2024$) as escalated at CPI after 2024.

This price and cost to YEC reflects the levelized capacity and non-fuel O&M costs to YEC as estimated for equivalent permanent new diesel generation capacity."

QUESTION:

a) Explain why a largely fixed cost needed to be escalated by CPI?

b) Why is $200/kW the standard and why is $175/kW not the standard for the Takhini greenfield plant?

ANSWER:

(a)

Please see response to YUB-YEC-1-27. The LCOC used as the benchmark levelized the fixed cost component to set a year 1 price that will reflect YEC weighted average cost of capital over the 40 year diesel plant life. This levelized price also assumed annual escalation at CPI.

(b)

Please see response to YUB-YEC-1-13(a) which notes as follows regarding the cost for greenfield new diesel generation capital and non-fuel O&M at (2024$) $200/kW-yr:

> This price is within the bottom end of the range for levelized cost of capacity (LCOC) estimates of YEC levelized cost of capacity (i.e., fixed capital and O&M costs, excluding fuel costs) for a 12.5 MW new diesel generation facility of $175

per kW (2019$) if located at Takhini without any property taxes, and $199.8 per kW (2019$) if located in Whitehorse with related property tax costs (see response to Undertaking #7 in BESS proceeding). The 2019 LCOC costs escalated at 2% per year for inflation to 2024 equal $193 and $220.6 per kW respectively.

ISSUE: **Unknown reference**

REFERENCE: **Application, page 25, PDF page 28**

QUOTE: "The effect on customer rates of energy and capacity purchases under the EPA is constrained by the agreed price and payment terms (see Section 2.4.3 of this Submission) and the actual dependable capacity and delivered energy provided by THELP."

QUESTION:

a) The application outline does not show a "Section 2.4.3". Please provide the correct reference and explain the meaning of the above paragraph.

ANSWER:

(a)

The correct reference should be to section 3.4 of the Submission which reviews the commercial terms of the EPA. Section 3.4.1 reviews key principals and section 3.4.2 provides a summary of EPA commercial terms relevant to the referenced quote from the Submission.

ISSUE: **Summer delivered energy**

REFERENCE: **Application, page 26, PDF page 29**

QUOTE: "Summer Delivered Energy (June-August) - summer energy deliveries, if requested by YEC, will be paid based on a Summer Delivered Energy Payment as provided in the EPA. This payment is equal to Summer Delivered Energy times 50% of the then current YUB approved blended fuel thermal price for YEC generation on the YIS."

QUESTION:

a) Is the price based on the last Board-approved GRA blended fuel thermal price, or is it based on the last approved GRA price plus any subsequent Rider F changes? Please explain.

ANSWER:

(a)

The summer energy price is based on the last Board-approved GRA blended fuel thermal price. The approach is the same as adopted in section 3(2) of OIC 2019/25 for setting the price for an IPP under an on-grid electricity purchase agreement. The intent is to reflect the latest Board-approved GRA blended fuel thermal price without the added complexities of addressing subsequent Rider F changes made by the utilities without the need for Board approval.

ISSUE: **Accounting treatment of EPA**

REFERENCE: **Application, page 26, PDF page 29**

QUOTE: "There is some uncertainty with respect to what, if any impact the EPA may have on YECs balance sheet (i.e., rate base). Based on preliminary assessments of the Agreement, YEC has concluded that this transaction does not contain a capital lease and therefore there is no balance sheet or rate base impact. This conclusion, however, is not final. The ultimate impact can only be known when the Project is complete and YECs auditors (the Auditor General of Canada) have reviewed the transaction."

QUESTION:

a) Provide the basis of the preliminary assessments of the agreement that led to YEC's conclusion.

b) If it is determined that the agreement operates as a capital lease, what are the impacts to the agreement and to customer rates?

c) Please explain why YEC has not sought an external opinion on the accounting treatment of the EPA.

ANSWER:

(a)

YEC assessed the accounting for this agreement through a review of applicable sections of International Financial Reporting Standards (IFRS) which applies to YEC as a Government Business Enterprise.

The question of whether the EPA will result in a long-term asset and liability on the balance sheet depends principally upon the following determinations:

- Whether either of the two situations that could result in the asset and liability being on balance sheet are applicable:

- Control and therefore consolidation of the counterparty; and
- Whether the arrangement is a lease or contains lease components under International Financial Reporting Standards ("IFRS").

- In the event the arrangement is a lease, whether any portion of the payments under the agreement are fixed or in-substance fixed lease payments required to be recorded as liabilities with a corresponding right-of-use asset.

Our preliminary accounting assessments under IFRS are as follows:

YEC does not have control, as defined in IFRS 10 *Consolidated financial statements*, or joint control, as defined in IFRS 11 *Joint arrangements*, over the counterparty to the arrangement, THELP. Specifically, YEC does not have the current ability to direct the activities of THELP that significantly affect THELP's returns, either unilaterally or shared with another party. YEC does not believe this determination to be highly subjective although it will not be subject to discussion with YEC's auditors until the agreement has been consummated.

Further, the agreement is not a lease in its entirety under IFRS because certain of the principal assets (notably, the Surprise Lake storage and control structure) support not only fulfilment of the contract with YEC but also the generation of power for third parties (i.e., Atlin, BC). YEC has concluded the utility does not control the use of such assets, as supported by the fact that YEC does not meet the criteria outlined in IFRS 16.B9, in particular:

- YEC does not have the right to substantially secure all the economic benefits of these assets because they are used for the benefit of both YEC and a third party; and
- YEC does not have the right to direct the use of such assets (which are subject to pre-existing agreements between parties that have no relationship with YEC).

There is significant judgment on the determination of whether the agreement otherwise contains lease components with respect to other assets owned by THELP and dedicated to the delivery of capacity and energy to YEC (such as the Upper and Lower Powerhouses, the power canal, penstock and transmission lines). The subjectivity arises because of the degree to which the use of the physical assets is interconnected, many activities are

subject to predetermined protocols mutually agreed by the parties under the EPA, and the degree to which each party has responsibility for certain decisions during different seasons throughout the term of the EPA.

In light the of the acknowledged complexity and judgment involved in these determinations, YEC considered whether any portion of the future payments would be recorded on YEC's balance sheet in the event any of these assets were determined to be leases. The principal provisions of IFRS 16 *Leases* that affect whether any portion of the payments constitutes a lease liability (resulting in a corresponding right-of-use asset, both recorded on YEC's balance sheet) are the extent to which the payments are:

a) Fixed payments (including in-substance fixed payments), in which case such payments constitute lease liabilities recorded on balance sheet at their present value; or

b) Variable payments (including payments which are dependent on the future performance or use of the underlying assets), in which case such payments do not constitute lease liabilities. IFRS 16.BC169 indicates that such payments could be viewed as a means by which the lessee and lessor can share future economic benefits to be derived from the use of the asset.

YEC identified that only the dependable capacity payments required more detailed scrutiny in considering whether any portion of the payments would constitute lease liabilities under IFRS 16, as all other payments under the agreement vary based on the electricity delivered, with no specified contractual minimum amounts.

The dependable capacity payments under the lease are determined annually as a result of a 24-hour performance test to be conducted in December, which measures the total energy delivered over the 24-hour test period. The results of this test are expected to vary year-to-year based on the amount of dependable capacity THELP can demonstrate the plant can deliver at the beginning of each winter season. Following the test, the minimum capacity payments for the ensuing winter period become fixed. However, as of the date of commencement of the lease, which is the date the plant becomes operational and able to generate electricity for YEC's benefit, the amount of these payments is undetermined and dependent on the future performance of the asset.

Pursuant to IFRS 16 and after consulting published guidance from the Big 4 accounting firms under both IFRS, and the same provisions in US GAAP, YEC has concluded that as expressly documented in published sources, even variable payments that are highly certain to occur do not result in lease liabilities if the payments are based on the performance or usage of the underlying asset, such as in the case of the dependable capacity payments described above.

On this basis YEC has preliminarily concluded that, subject to future concurrence with YEC's auditor, energy and capacity payments will not be recorded on YEC's balance sheet under IFRS prior to the year to which they relate.

(b)

Unless the YUB directs an exception from GAAP, a lease asset (right-of-use asset under IFRS 16) would be included as part of rate base and the utility would be entitled to charge ratepayers a return on that asset. Such treatment would have a direct impact to ratepayers. As evidenced in this Submission, YEC has carefully analyzed the impact of this agreement versus lowest cost alternatives. Should YEC auditors determine that recording an asset is necessary, YEC will investigate options for ratemaking purposes to ensure the financial advantages of this agreement are not diluted by this accounting treatment.

(c)

YEC consulted a major accounting firm to advise it on this analysis. To YEC's knowledge, accounting firms will not provide an opinion on accounting outside of a formal audit process. YEC believes that, based on the terms of the agreement and the known industry practice, it is reasonable to conclude that there is no balance sheet impact. However, YEC was also advised that the nature of the accounting determinations involve subjectivity and therefore a final determination will only be possible when an audit is performed after the project is in service.

ISSUE: **YEC costs**

REFERENCE: **Application, page 27, PDF page 30**

QUOTE: "The EPA also provides for any YEC costs for studies and other works to be fully funded by the Project (i.e., by THELP and not by the utilities) with advance payments as required – the only costs not funded by THELP relate to YEC's EPA negotiation costs and costs related to this Submission to the YUB."

QUESTION:

a) Provide examples of what types of studies may be required and any estimates of costs to customers for further studies.

b) Provide an itemized breakdown of YEC's costs associated with the EPA planning, analysis, consultations, etc.

ANSWER:

(a)

The studies referenced in the quote are those required for the Buyer-AEY System Interconnection Report, including evaluation of the impact of Seller's Plant on the reliability of Buyer-AEY System, the scope of required Buyer-AEY System Upgrades to address these impacts, and planning-level estimates of required Buyer-AEY System Upgrade Costs. No costs to customers are estimated to be required for further studies.

(b)

The table below captures the costs incurred by YEC to date related to planning, analysis and negotiations for this EPA.

Expense Type	
Legal	507,949
Consultants	311,056
Contractors	172,830
Internal Labour	18,867
AFUDC	10,150
Travel & Miscelaneous	5,311
	1,026,163

Contractor costs relate to system impact and operational studies that YEC expects to recover from the seller. The remaining costs are related to EPA negotiations and are expected to be recovered through rates.

These costs will increase as YEC will incur costs as part of finalization of Conditions Precedent under the EPA. YEC estimates approximately $0.175 million will be recoverable from THELP, subject to final reconciliation and invoicing. YEC is separately tracking the costs of this proceeding and will apply for recovery in accordance with YUB rules.

ISSUE: **EPA prices and energy deliveries**

REFERENCE: **Application, page 28, PDF page 31**

QUOTE: "The EPA prices are sensitive to firm energy versus non-firm energy deliveries over the year – a factor which will tend to reduce cost impacts for YEC from variances in actual versus LTA costs related to EPA energy deliveries."

QUESTION:

a) Please provide further explanation on EPA prices and sensitivity because of deliveries.

b) How would the factor work?

ANSWER:

(a) and (b)

Energy price payments for Winter Period energy deliveries per section 8.2 of the EPA include two amounts (see also Table 3-1 of the Submission):

1. The Firm Winter Energy Price is paid for the first 25.2 GWh of Delivered Energy and Monthly Constraint Energy during the Winter Period of a calendar year; and

2. The Non-Firm Winter Energy Price is paid for Delivered Energy and Monthly Constraint Energy in excess of 25.2 GWh during the Winter Period of a calendar year.

As summarized in Table 3-1 of the Submission, these prices in the EPA are in 2024$ with one set of firm and non-firm prices for 2024-2034 and another set of prices for 2035 and the balance of the EPA term. The firm energy price is higher than the non-firm energy price throughout the EPA term. These prices all escalate after 2024 at 50% of CPI.

Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for determining these firm and non-firm energy prices. Further explanation is provided in YUB-YEC-1-11 and YUB-YEC-1-12.

ISSUE: **Clean Energy Act**

REFERENCE: **Application, page 28, PDF page 31**

QUOTE: "Shortages in LTA Project energy deliveries relative to the LTA forecasts in this Submission could prevent YEC from meeting the 93% Renewable Portfolio Standard in the expected new Clean Energy Act. The YEC financial/ratepayer impact of such a shortfall is unknown at this time, e.g., it could potentially result in fines."

QUESTION:

a) Please explain why YEC would expect potential fines for violations of the Clean Energy Act.

b) Would any potential fines be considered a shareholder expense rather than a ratepayer expense? Would YEC attempt to have such fine payments added to its rate base?

ANSWER:

(a) and (b)

While the exact terms of this Act are not known today, YEC believes it is normal practice for legislation of this nature to include penalties against individuals or entities who fail to comply with the Act's terms. The referenced quote states that the YEC financial/ratepayer impact of such a shortfall is unknown at this time. The example of potential fines is simply noting the possibility of a financial penalty – it is not suggesting that YEC expects this specific possibility. YEC has no assessment at this time as to how such potential fines would be considered with regard to rates. There is, however, the possibility that such costs might be added to rates.

ISSUE: **No industrial load**

REFERENCE: **Application, page 29, PDF page 32**

QUOTE: "However, over most of the EPA Term (i.e., from 2035 through to July 31, 2064) the EPA prices assume no industrial load – thereby minimizing risks to YEC and to customer rates."

QUESTION:

a) In the scenario of no industrial load post-2034, would EPA purchases displace YEC hydro generation for the YIS system? Please explain why or why not.

ANSWER:

(a)

Yes, under the assumed scenario of no industrial load post-2034 a material portion of EPA purchases (but not all of these purchases) would displace YEC hydro generation on the YIS. The winter energy prices in the EPA for the post-2034 have been reduced to reflect the reduced expected thermal displacement benefits based on this scenario – with provision for Additional Payment if there is Added Load above this scenario's forecast (see Table 3-1 of the Submission for a summary of the relevant energy prices).

See the response to YUB-YEC-1-11 and YUB-YEC-1-12 for a more detailed review of how the EPA energy price determinations reflect the extent of expected YIS thermal generation displacement versus YEC hydro generation displacement.

ISSUE: **Costs arising from the Implementation Agreement**

REFERENCE: **Application, page 29, PDF page 32**

QUOTE: "YEC will seek to recover from AEY, through the Implementation Agreement, any such costs due to a Non-Permitted System Constraint on the AEY System."

QUESTION:

a) Explain the Implementation Agreement and how cost recovery under the agreement would operate.

ANSWER:

(a)

Under the Atlin EPA (as is also case for SOP EPAs for the YIS), YEC as Buyer is the party responsible to Seller for purchases, as well as for various other activities, including completion of System Upgrades, operation of the YIS, and any payments required to Seller as a result of a Non-Permitted System Constraint on the YIS. The YIS affected by the Atlin EPA includes the AEY System as well as the system owned and operated by YEC.

Section 2.1(d)(ix) of the Atlin EPA provides a Condition Precedent requiring YEC to have entered into an implementation agreement with AEY for the implementation of this EPA on terms and conditions satisfactory to YEC, acting reasonably. The purpose of the implementation agreement is to address all of the necessary arrangements required between YEC and AEY in order for YEC to implement the EPA. The EPA has been amended to extend the date to March 31, 2022 for completing this requirement. This agreement is still being finalized by the parties. Similar implementation agreement requirements have been finalized for the SOP EPAs.

A Non-Permitted System Constraint can result in a requirement for payments to be made by YEC to THELP for energy that THELP could not deliver due to the System Constraint. See YUB-YEC-1-25 for a more detailed review of these provisions.

The YEC-AEY implementation agreement for the Atlin EPA will provide for mechanisms to track any System Constraint, its location on the AEY System versus the YEC system, the apparent cause of the System Constraint and its impact on Seller energy deliveries. In cases where a Non-Permitted System Constraint requires YEC to pay THELP for Monthly Constraint Energy, the YEC-AEY implementation agreement will provide for YEC to seek recovery from AEY for any such costs due to a Non-Permitted System Constraint on the AEY System. The details for this provision are yet to be finalized for this agreement.

ISSUE: **Water Storage Savings**

REFERENCE: **Application, Appendix A, Figure A1-1, page A-5, PDF page 40**

QUOTE:

QUESTION:

a) Figure A1-1 shows Water Storage Savings of 2.8 GWh/yr. Explain what this value relates to and how that amount was determined.

ANSWER:

(a)

Water Storage Savings represents the value of thermal displacement avoided due to EPA deliveries enabling added hydro storage on the YIS. It is distinguished from thermal displacement that occurs directly due to EPA deliveries. As shown in Figure A1-1, total LTA thermal displacement of 19.6 GWh/year is the total resulting from direct thermal displacement (16.7 GWh) and water storage savings thermal displacement (2.8 GWh).

As noted in Table A1-1, LTA thermal displacement has been estimated based on YECSIM model simulation runs for 38 water years. Key assumptions are noted in this table.

ISSUE: **Conditions Precedent**

REFERENCE: **Application, Appendix B, page B-5, PDF page 49**

QUOTE: TRTFN Approval: Section 2.1(d)(vi) of the EPA Conditions Precedent specifies that, on or before May 31, 2022, Seller will have obtained approval of the EPA by the TRTFN by way of Clan Directive or a Joint Clan Meeting Mandate.

QUESTION:

a) Prior to the negotiation of the EPA, did YEC engage in any consultations with TRTFN or other persons/parties who would be impacted by TRTFN approval as a condition precedent?

b) Please describe the engagements involving TRTFN.

c) Over what time period did this stakeholder engagement occur?

d) Please explain the difference in TRTFN approval between Clan Directive and a Joint Clan Meeting Mandate.

e) Who would have to vote for TRTFN approval? What happens if TRTFN approval is denied or does not occur by May 31, 2022?

f) What stakeholder engagement occurred for transmission line construction between the Yukon/BC border and Jakes Corner?

g) Which parties were involved in the consultation process?

h) What project approvals are required from First Nations for any project construction in Yukon in general, and are there any other approvals required that are specific to this project?

i) If there has been First Nation consultation, has any accommodation of First Nation interests been required or made, and if so, what costs have been or will be incurred by YEC in that regard?

ANSWER:

(a)to (c), (f),(g) (i)

Prior to negotiating the EPA, Yukon Energy did not engage in consultations specific to the Atlin Project.

The Atlin Project is being developed by THELP, and THELP is therefore the party responsible for all related First Nation engagement and consultation. Yukon Energy does not have details regarding how THELP has carried out these responsibilities. Yukon Energy has also not conducted any engagement or consultation with TRTFN or other First Nations with regard to this project, and does not expect to incur any costs in this regard or any costs for accommodation of First Nation interests with regard to this project.

THELP consultation and engagement on the Project transmission development from the Yukon/BC border and Jakes Corner were provided as required in its Project Proposal submission to YESAB, and addressed as required by YESAB prior to issuing its September 10, 2021 Evaluation Report recommending that this component of the Project proceed.

(d) and (e)

Yukon Energy is not aware of the specific differences in TRTFN approval between a Clan Directive and a Joint Clan Meeting Mandate, or who specifically would have to vote for either such approval. The requirements in this instance derive from THELP needing the approval of its owners. The referenced condition precedent requires that one of these approvals be secured by TRTFN on or before May 31, 2022.

If the required approval is denied or does not occur by May 31, 2022, the EPA cannot proceed to come into force and the Project cannot proceed unless the specified condition precedent date is extended or waived by agreement of YEC and THELP.

(h)

In general, First Nation approvals are required in Yukon for project activities on Settlement Land. Such approvals were required, for example, from two First Nations for development

of the Carmacks-Stewart Transmission Project that required facilities to be located on certain Settlement Lands. No such approvals are required for the Atlin Project.

ISSUE: **Thermal generation displacements**

REFERENCE: **Application, Appendix B, footnote 14, page B-10, PDF page 54**

QUOTE: "Thermal generation reductions vary depending on Yukon Integrated System (YIS) water conditions. The LTA estimates are derived based on simulation assessments for 38 different YIS water years, taking into account direct thermal displacements by Atlin energy and also indirect thermal displacements by Atlin energy through facilitating enhanced hydro storage on the YIS that enables increased winter hydro generation in some of the water years. Estimates are derived from YECSIM model LTA assessments without and with Atlin energy deliveries, based on forecast YIS firm generation load requirements in 2024 and 2035 and planned YIS capability without the Project (including expected water use licence conditions, YEC hydro plant uprates and other expected IPP generation purchases by YEC). See Appendix A, Table A3-1 for 2024 and 2035 LTA thermal estimates (and related assumptions) with and without the Project."

QUESTION:

a) Please explain the term "indirect thermal displacements".

b) Does the quote above mean that YEC will use energy from the EPA and withhold YEC hydro generation?

ANSWER:

(a) and (b)

"Indirect thermal displacements" occur where certain EPA deliveries allow YEC to curtail hydro generation and thereby increase hydro reservoir levels. This additional storage can then be used in the future to secure added thermal displacement.

Please see YUB-YEC-1-48 for additional information on this thermal displacement and how it differs from “direct thermal displacement”, as well as estimates for each as provided in YEC’s Submission.

ISSUE: **Firm Winter Energy Price**

REFERENCE: **Application, Appendix B, footnote 15, page B-10, PDF page 54**

QUOTE: "Section 8.2 of the EPA provides for monthly payment of the Firm Winter Energy Price (for estimated low flow water year winter delivery levels) and the Non-Firm Winter Energy Price (balance of winter deliveries) for Delivered Energy and Monthly Constraint Energy during the Winter Period."

QUESTION:

a) Please provide the basis for the statement in the above-quoted footnote.

b) Please explain the difference between "firm winter energy" and "non-firm winter energy".

c) Is all pricing based on assumed low-flow water years? Please explain why or why not.

ANSWER:

(a)and (b)

Energy price payments for Winter Period energy deliveries per section 8.2 of the EPA include two amounts (see also Table 3-1 of the Submission):

1. The Firm Winter Energy Price is paid for the first 25.2 GWh of Delivered Energy and Monthly Constraint Energy during the Winter Period of a calendar year; and

2. The Non-Firm Winter Energy Price is paid for Delivered Energy and Monthly Constraint Energy in excess of 25.2 GWh during the Winter Period of a calendar year.

As summarized in Table 3-1 of the Submission, these prices in the EPA are in 2024$ with one set of firm and non-firm prices for 2024-2034 and another set of prices for 2035 and

the balance of the EPA term. The firm energy price is higher than the non-firm energy price throughout the EPA term. These prices all escalate after 2024 at 50% of CPI.

(c)

All pricing is not based on assumed low flow water years at Atlin. The EPA pricing overall reflects LTA water availability at Atlin. Only the firm energy price is based on the low flow year. The non-firm energy price reflects the balance of thermal displacement from LTA flows in excess of the low flow year.

Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for determining these firm and non-firm energy prices. Further explanation is provided in YUB-YEC-1-11 and YUB-YEC-1-12.

ISSUE: **Delivered Energy**

REFERENCE: **Application, Appendix B, page B-12, PDF page 56**

QUOTE: "First 25.2 GWh/year of Delivered Energy and Monthly Constraint Energy – Firm Winter Energy Price of $0.132/kWh for 2024, increased by 50% of CPI for each Year after 2024 until completion of 2034."

QUESTION:

a) Please explain the difference between "Delivered Energy" and "Monthly Constraint Energy".

ANSWER:

(a)

Per section 1.45 of the EPA, Delivered Energy is the amount of Energy delivered in KWh by Seller to Buyer at the POI in that month as recorded by the Meter. If a Party disputes the accuracy of the Meter, the amount of Delivered Energy is as determined under Section 3.8.

Monthly Constraint Energy is defined in Schedule "F" of the EPA and relates to circumstances where there has been a Non-Permitted System Constraint. In summary, Monthly Constraint Energy requires YEC payment for winter energy that THELP could not deliver due to a Non-Permitted System Constraint. Please see YUB-YEC-1-25 for a more detailed explanation of Monthly Constraint Energy and how it is determined.

ISSUE: **Estimated thermal displacements**

REFERENCE: **Application, Appendix B, page B-12, PDF page 56**

QUOTE: "If Carbon Charge included in YUB approved YEC rates, pay 50% of carbon tax per kWh times estimated thermal displacement during these winters (estimated at 63.5% of all winter deliveries in these years)."

QUESTION:

a) Please explain how the 63.5% estimate was determined.

ANSWER:

(a)

The referenced quote applies to a Carbon Charge during the years 2024 to 2034. Based on Table A3-1 analysis for this period, the 63.5% equals the expected LTA thermal displacement from winter EPA deliveries (19.563 GWh at row 5) divided by LTA EPA deliveries (30.8 GWh at row 1). Similarly, for the years 2035 and the balance of the EPA term, this percentage is adjusted to 48.7% (15.003/30.8).

ISSUE: **Price for electricity under electricity purchase agreement**

REFERENCE: **OIC 2019/25, page 2, PDF page 2, Section 1 definitions**

QUOTE: "'Independent power production facility' means a facility in Yukon…"

QUESTION:

a) Is the pricing under OIC 2019/25 only applicable to an independent power production facility?

ANSWER:

(a)

Yes.

ISSUE: **Carbon charges**

REFERENCE: **Application, page 11, PDF page 14**

QUOTE: "If in the future a carbon charge is approved by YUB for recovery through customer rates, THELP can get paid up to 50% of YEC's added cost saving from thermal displacement."

QUESTION:

a) Please confirm if the CPI includes any carbon taxes levied on the ratepayer.

b) Please confirm if any additional charge due to a carbon tax would in effect be double dipping.

ANSWER:

(a)

YEC does not understand the basis of this question, as "CPI" is not referenced in the above quote or in the EPA sections addressing the carbon taxes.

(b)

No, there would not be any double dipping.

The EPA energy price paid to THELP is based on forecast fuel cost savings that YEC secures due to displacement of LTA thermal generation as a result of the EPA winter energy deliveries. If a carbon tax is approved by the YUB for recovery though customer rates, then YEC forecast fuel cost savings secured by YEC due to displacement of LTA thermal generation is increased. Under the related EPA pricing provision, THELP would get up to 50% of this added YEC cost saving.

ISSUE:

REFERENCE: **Application, Appendix B, page B-10, PDF page 54**

QUOTE: 2024 and 2035 Winter Energy Prices: the winter energy price has been estimated for 2024 based on expected loads with mines connected, and escalated at 50% of CPI each subsequent year until 2035.

QUESTION:

a) Please explain how the Consumer Price index (CPI) is derived.

ANSWER:

(a)

The CPI is defined in Appendix A of the EPA, section 1.43 as follows:

> **"CPI"** means the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada in table 18-10-0004-01 or its equivalent substitute or replacement as agreed to by the Parties, acting reasonably. For clarity, the CPI index value for January, 2019 is 133.6.

ISSUE: **Alternatives to the project**

REFERENCE: **YEC 2016 Resource Plan Part 2, page 5-31, PDF page 3**

QUOTE:

Table 5-27. Small Hydro Resource Option Technical and Financial Attributes

Annual Energy GWh/yr	Firm Energy GWh/yr	Installed Capacity MW	Dependable Capacity MW	Levelized Cost of Energy $/kWh	Levelized Cost of Capacity $/kW·yr	Project Life Years	Lead Time Years	Dispatch-able Y/N
Drury Lake								
31.7	31.7	8.1	8.1	0.19	700	65	6	Y
Tutshi Windy Arm								
56.6	56.3	7.2	7.2	0.14	1100	65	6	Y
Wolf River								
95.6	86.9	20	2.8	0.14	700	65	6	Y
Finlayson River								
138.9	138.9	17.6	17.6	0.12	1000	65	6	Y
Atlin/Pine Creek								
36.1	22.3	8	5.5	0.13	806	30	6	Y
Anvil Creek								
41.3	31	9.8	2.5	0.17	700	65	6	Y

QUESTION:

a) Please explore the financial ramifications for the Yukon ratepayers for the projects Drury Lake, Atlin/Pine Creek and Anvil Creek.

b) Would the energy produced by a Yukon Consortium for a project located in Yukon fall under OIC 2019/25?

c) In financial terms, what is the difference between this EPA and projects that would fall within OIC 2019/25?

ANSWER:

(a)

The table provided in the preamble is for small hydro projects reviewed in YEC's 2016 Resource Plan. Since then, YEC updated the small hydro resource options in the 10-Year Renewable Electricity Plan.

For the 10-Year Renewable Electricity Plan YEC engaged Knight Piésold Ltd. (KP) to update and further develop a desktop review of the potential hydroelectric projects in Yukon and northern BC. This study resulted in a refined and updated list of five small hydroelectric projects of interest, Atlin and four others, with capacities ranging from 8 MW to 13 MW and with four of the five having storage capabilities.

Table 3, Refined List of Future Potential Resource Options, of the 10-Year Renewable Electricity Plan provides an updated list of small hydro options [the technical report is available at YUB-YEC-1-32, Attachment 1].

To date the review of the referenced small hydro projects by Yukon Energy were limited to the desktop level pre-feasibility assessments conducted for 2016 Resource Plan and 10-Year Renewable Electricity Plan.[1] At this time, the financial ramifications to Yukon ratepayers is limited to the cost of those studies. Potential future financial ramifications to Yukon ratepayers if each project was to be developed will depend on subsequent financial assessments during project feasibility and implementation stages of development.

No feasibility studies or ratepayer impact analysis were prepared for Drury Lake or Anvil Creek, while Atlin Hydro ratepayer impact analysis are prepared for the EPA purposes. The following is specifically noted regarding the three projects referenced in the question.

Atlin Hydro Expansion

Atlin Hydro Expansion was selected in the 10-Year Renewable Electricity Plan as a potential near term option in the portfolio because of its ability to supply both dependable capacity and firm energy, and because of its significantly shorter project development timeline when compared to other greenfield hydro options. Estimates of project

[1] The 2016 Resource Plan also notes previous studies including 1989, 1990, 1991 Hydro Investigations [S. Demers] and Assessment of Potential Hydro Sites [KGS Group, 2008].

deliverables (6 MW dependable capacity and 44.7 GWh/yr energy) have changed significantly today, as have the estimated costs at $131 million. The levelized cost of energy was estimated at $0.17/kWh without grants ($0.10/kWh with grants) and levelized cost of capacity at $1,270/kW-year without grants ($708/kW-yr with grants).

It was understood that the Atlin project would be developed as an expansion of an existing hydro facility owned by the local First Nation, and that the project would therefore likely be under an EPA with YEC.

The current Submission details EPA capacity and energy pricing for the Atlin project which includes the following [detailed table provided as Table 3-1 in the Submission]:

Pricing	2024-2034	2035 & Beyond
Energy Delivered		
Firm Winter Energy Price (Jan-May,Sept-Dec) (first 25.2 GWh delivered in winter)	$0.132/kWh in 2024 plus 1/2 CPI	$0.107/kWh in 2024 plus 1/2 CPI after
Non-Firm Winter Energy Price (all energy after first 25.2 GWh delivered)	$0.072/kWh in 2024 plus 1/2 CPI	$0.027/kWh in 2024 plus 1/2 CPI after
Dependable Plant Capacity Committed		
LCOC Reference Price	$200/kW-yr in Dec. 2023 plus CPI after	

The capacity and energy pricing for the Atlin EPA was determined based on benefits the project is expected to provide to the YIS, including dependable capacity during critical winter period and LTA thermal displacements benefits as discussed in the Submission.

The financial ramifications for ratepayers are severely constrained by the EPA (i.e., development and project costs risks are borne by THELP, and EPA prices are based on expected thermal option costs rather than actual project costs).

Drury Lake

The Drury site was evaluated as both a run of river project and a storage project. However, only the storage option was included as part of five small hydroelectric projects of interest [run of river option was not attractive due to low winter energy].

The project scale was identified to have 10 MW dependable capacity with 30.6 GWh annual energy at a capital cost of $110.5 million. The levelized cost of energy based on this pre-feasibility assessment was estimated at $0.21/kWh and levelized cost of capacity at $635/kW-year.

Experience with hydro projects demonstrates potential for material cost escalation as assessments move through from pre-feasibility to feasibility studies, from studies to final design and contracting, and from contracting to final commissioning. Drury Creek is a greenfield site that was expected to require YEC to be the party developing the project.

YEC does not have detailed ratepayer impact analysis for the project as it requires consideration of LTA thermal displacement rather than using project levelized cost of energy based on total energy generated over the year.

Anvil Creek

The project was not included as part of shortlisted small hydro projects in the 10-Year Renewable Electricity Plan.

A few run-of-river configurations were considered up and down Anvil Creek. The project location has previously been associated with Anvil Lake, a site that does not offer the same generating opportunities. The most attractive options for Anvil Creek assume long tunnels, resulting in average to higher LCOE returns, as such the project was not shortlisted. It was only possible to fully regulate the river for winter generation with a very tall dam structure, which proved to be cost prohibitive (i.e., $1 billion for 30 MW of firm winter generation).

(b)

In general, subject to meeting all relevant regulations and terms, a renewable energy hydro project located in Yukon, owned by parties other than the utilities, and supplying the YIS under an EPA with YEC would fall under OIC 2019/25 with all energy delivered priced on the basis of the applicable blend fuel thermal price last approved by the Board and inflated each year thereafter at 50% of CPI.

(c)

Under OIC 2019/25 for the on-grid projects:

- The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility's average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

- This price is subject to annual escalation at 50% of the CPI increase.

- Provision is also made for compensation (section 5(1)) as well as for utility recovery of costs (section 2).

In summary, OIC 2019/25 requires that for each kWh delivered the utility must pay the last approved blended fuel cost regardless of the thermal displacement benefits of that delivered energy.

In contrast, the Atlin EPA firm and non-firm prices have been set based on LTA thermal displacement benefits. Atlin EPA pricing also focuses on energy delivered during the "winter" period [defined as Jan-May, Sep-Dec], while for SOP IPP projects the utility pays the specified price for all annual generation.

The Atlin EPA also includes a capacity payment price which is not included in the OIC 2019/25.

Section 4.2 of YEC's Submission provides the following assessment of the difference between this EPA and equivalent SOP IPP developments under OIC 2019/25:

> "The EPA effect on customer rates is materially lower than equivalent SOP IPP renewable supplies. Total annual cost at 2024$ prices for EPA deliveries to YEC for LTA energy and dependable capacity equals $5.3 million/year until the end of 2034, and $4.5 million/year thereafter.[2]

[2] The $5.3 million/year (2024$) until the end of 2034 assumes 8.0 MW dependable capacity ($1.6 million/year) plus 30.8 GWh/year winter delivered energy ($3.7 million/year per Appendix A, Table A3-2). The Project is capable of providing 5.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 5.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.5 million/year (price at 50% of the approved blended fuel cost).

- In contrast, SOP IPP deliveries for renewable projects with the same annual LTA energy delivery capability (36.2 GWh/year including summer period energy) and the same 2024$ YEC blended fuel cost of $0.19/kWh would cost YEC $6.88 million/yr. for energy only.

- Additional costs would also be needed with SOP IPP options in order to provide the equivalent 8.0 MW of dependable capacity from another new source. The least costly new source would likely be new thermal generation with an LCOC (2024$) of at least $200/kW-year or $1.6 million/year for 8.0 MW."

ISSUE: **BC Hydro Supply Agreement**

REFERENCE: **Application, page 2, PDF page 5**

QUOTE: "In 2009 the TRTFN, through an affiliate of THELP, developed a 2.1 MW hydroelectric power station at Atlin, BC, on Pine Creek with hydro storage at Surprise Lake (the "Existing Plant"). The Existing Plant has an existing electricity purchase agreement with BC Hydro to supply BC Hydro load at Atlin until 2033. THELP expects that a further EPA will be negotiated with BC Hydro for supply after 2033."

QUESTION:

a) Please provide a copy of the agreement referenced above.

ANSWER:

(a)

Please see response to YUB-YEC-1-8.