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

AMENDED ROUND 1 IRS

April 20, 2022

City of Whitehorse
(CW)

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 in any Year, whether above or below the LTA, will all have the same ~~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: **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 May ~~rch~~ 31, 2022;
- 2.1(d)(ii) extended from February 15, 2022 to May 31~~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 May ~~rch~~ 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.

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 8.5 to 8.75 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 Sections 7.2(a) and 7.3 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).

REVISED RESPONSE

On March 16, 2022 Mr. Yee filed Notice of Motion regarding YEC's response to b) part of this IR. Mr. Yee specifically notes that YEC did not provide the number of diesel rentals for each season for 2022-2035 as requested in the question.

In his Motion, Mr. Yee modified his question and included a table requesting YEC to fill the missing information that covers 2017/18 through 2041/42 years. The modified question

also requests YEC to specify the number of rentals before and after the Amended Atlin EPA, Moon Lake pump storage as well as other additional resources.

Table 4-1 of the Amended Application~~, as revised in response to NY-YEC-1-6 a) and b),~~ provides forecast non-industrial peak, dependable capacity and capacity shortfall under N-1 for the period from 2021/22 through 2030/31 and Figure 4-1 of the Application illustrates similar information that extends to 2041/42 years. The information from Table 4-1 and Figure 4-1 is used to populate the table below to provide information as requested by Mr. Lee in his Motion for further information, however, the table excludes the years 2017/18 through 2020/21 as the table and figure in the Amended Application did not include those years as they are not relevant and not useful to this review process; in addition, information for these years was not included in the original information request.

The number of spares will depend on total number of rental units, the number of locations, and potentially other considerations relating to requirements and costs. Therefore, excluding 2021/22, the table does not include spares.

	Number of Diesel Rentals excluding spares			
	Before Committed and Planned Supply Options	After Diesel Replacements, Whitehorse #2 Uprate, BESS and DSM	After Atlin	After Moon Lake [Phase I and Phase II]
	A	B	C [incl. B]	D [incl. C]
2021/22	17	15	15	15
2022/23	19	16	16	16
2023/24	23	8	8	8
2024/25	25	10	5	5
2025/26	27	12	7	7
2026/27	29	14	9	9
2027/28	31	16	11	11
2028/29	34	18	14	0
2029/30	36	21	16	0
2030/31	39	24	19	0
2031/32	40	25	20	0
2032/33	42	26	21	0
2033/34	42	26	21	0
2034/35	42	27	22	0
2035/36	43	28	23	0
2036/37	44	29	24	0
2037/38	44	29	24	0
2038/39	45	29	24	0
2039/40	45	29	25	0
2040/41	45	30	25	0
2041/42	46	30	25	0

	Number of Diesel Rentals excluding spares			
	Before Committed and Planned Supply Options	After Diesel Replacements, Whitehorse #2 Uprate, BESS and DSM	After Atlin	After Moon Lake [Phase I and Phase II]
	A	B	C [incl. B]	D [incl. C]
2021/22	17	15	15	15
2022/23	19	16	16	16
2023/24	23	8	8	8
2024/25	25	10	6	6
2025/26	27	12	7	7
2026/27	29	14	9	9
~~2027/28~~	~~31~~	~~16~~	~~11~~	~~11~~
2028/29	34	18	14	0
2029/30	36	21	16	0
2030/31	39	24	19	0
2031/32	40	25	20	0
2032/33	42	26	22	0
2033/34	42	26	22	0
2034/35	42	27	23	0
2035/36	43	28	24	0
2036/37	44	29	24	0
2037/38	44	29	24	0
2038/39	45	29	25	0
2039/40	45	29	25	0
2040/41	45	30	25	0
2041/42	46	30	26	1

Notes:

1. Assumes diesel rental unit of 1.8 MW (this may change in future).
2. Based on Table 4-1 of the Amended Application~~, as revised in response to NY-YEC-1-6 a) and b),~~ which provides forecast non-industrial peak, dependable capacity and capacity shortfall under N-1 for the period from 2021/22 through 2030/31 and Figure 4-1 of the Application which illustrates similar information that extends to 2041/42 years. Moon Lake pumped storage is a proposed future project that requires material grant funding to complete feasibility studies, as well as to proceed with actual development – its timing, if it proceeds, is likely to be delayed beyond time forecast in the 10-Year Renewable Electricity Plan.

John Maissan
(JM)

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:

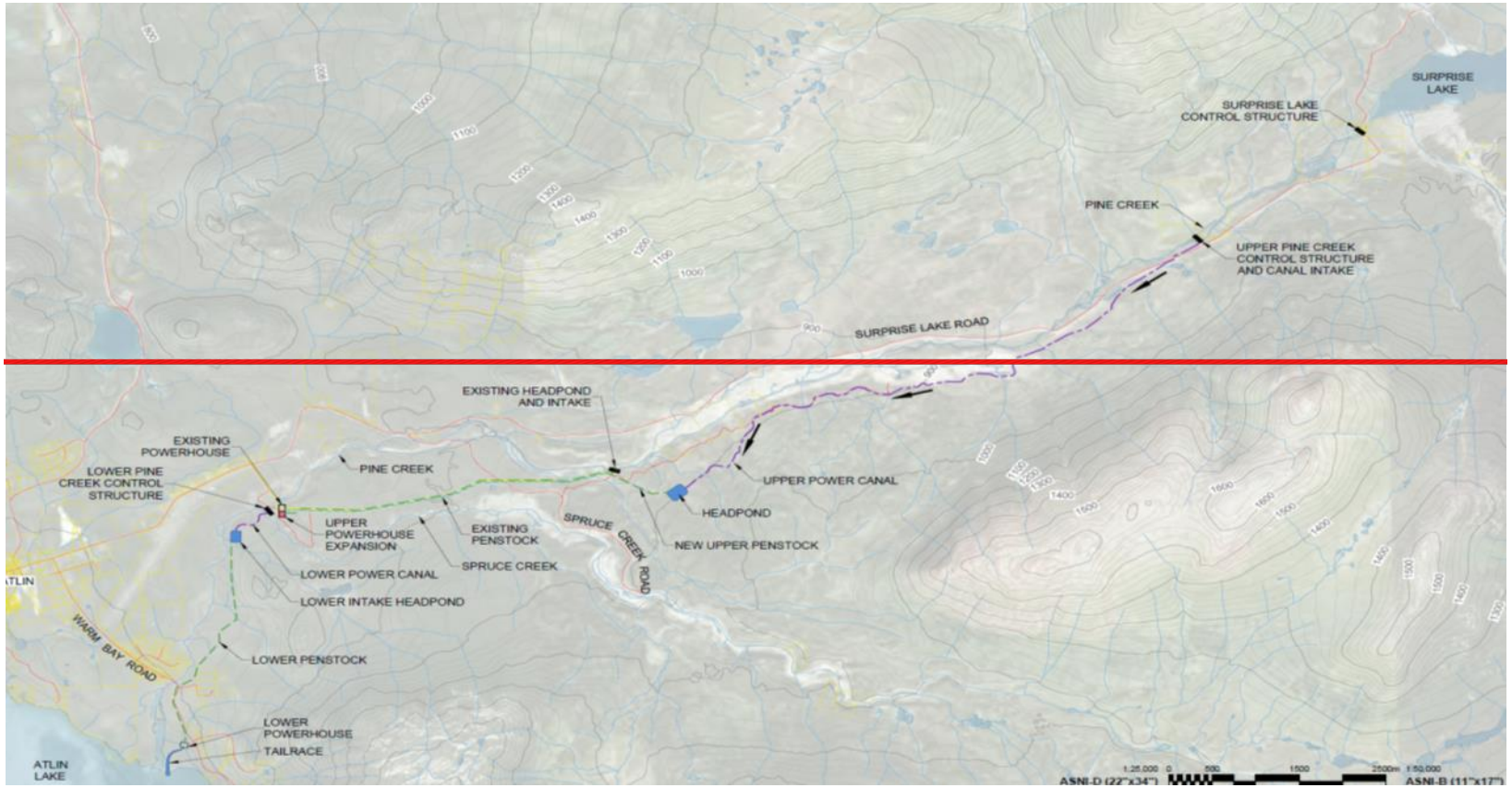
(a)

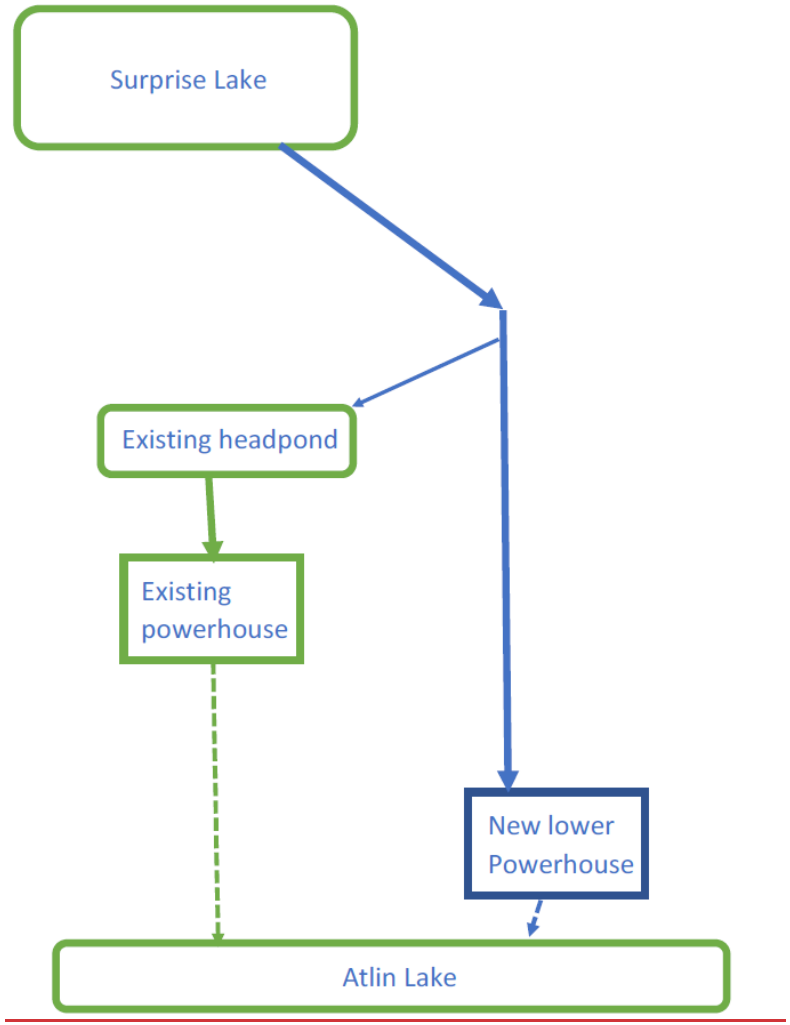
Appendix 1 provides an expanded Figure 2-1 so that all project components can be clearly seen.

(b)

The Atlin Project will have a new Penstock from Surprise Lake to the Powerhouse. The Existing Plant is also planned to have a tap from the same new Penstock that originates at Surprise Lake. ~~a different penstock than the existing plant, with a different head pond.~~ The beginning of the new ~~upper powerhouse p~~Penstock at Surprise Lake is shown in Figure 2-1 attached (the Penstock is the larger solid blue line between Surprise Lake and ~~– the new penstock then continues to the upper powerhouse beside the existing penstock~~the new lower Powerhouse).The tap from the new Penstock to the Existing Plant is also shown on Figure 2-1 attached (the tap is the smaller solid blue line between the Penstock and the existing headpond that then connects to the existing powerhouse).

Appendix 1 - Expanded Figure 2-1




Surprise Lake
Existing headpond
Existing powerhouse
New lower Powerhouse
Atlin Lake

1
2

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 $0.135~~2~~/kWh for 2024-2034 and [$0.097~~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~~ Winter E~~e~~nergy P~~p~~ric~~es~~~~ings~~ are determined based on total YEC load, including industrial load as reviewed in Table~~s~~ 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 34.0~~0.8~~ GWh LTA energy and 23.4~~5.2~~ 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:

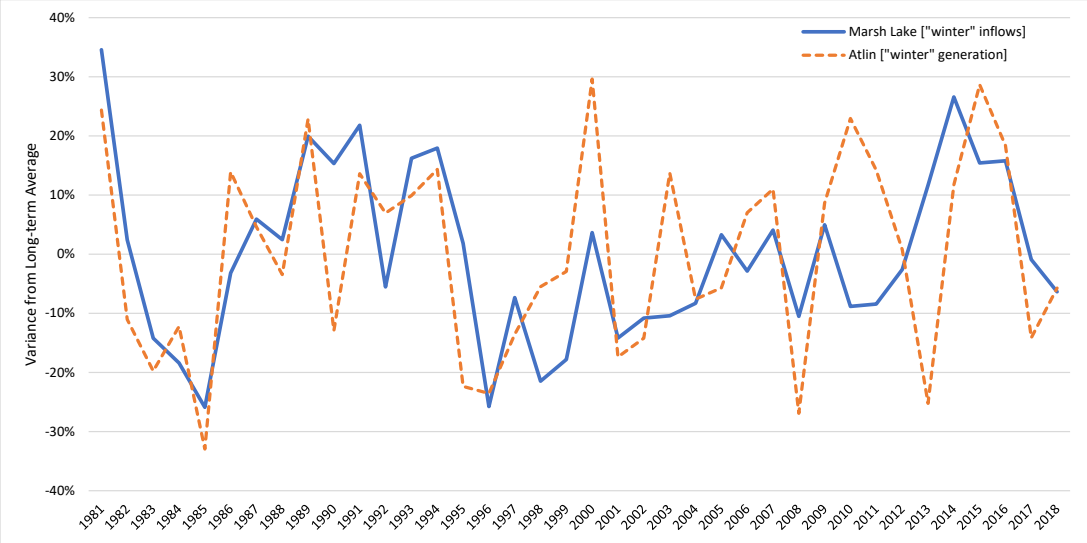
(a) through (c)

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 1981-20181993 water years to simulated Atlin generation for the same water years.[1]

[1] As illustrated in the Submission Table A1 in Appendix A Atlin generation estimates are based on modeled inflows for 1970-2020available for 1963-1993 and 2015-2019 water years. YEC LTA hydro generation estimates are based on 1981-2018 water years. Therefore, Tthe figure uses 1981-1993 2018 years which are available for both Marsh Lake and Atlin. The inflows are for Jan 1- May 15 and Sep 1 – Dec 31 to match Atlin generation period assumed in Table A1 in Appendix A.



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 LTA Atlin~~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).

REVISED RESPONSE

(a) and (b)

On March 14, 2022, Mr. Maissan by email correspondence to the Board requested further information regarding this response noting that the response did not include a column of figures (estimates) for the summer surplus generation and "without some hard figures as to what the actual surplus is or will be one cannot get a good overall picture of the YIS and its winter - summer energy imbalance." Mr. Maissan requested that YEC provide this further information.

Please see updated Table 1 and 2 below. For the purposes of this analysis, summer months are May through October which differs from Summer Period as defined in the EPA (June through August).

With respect to the source of summer surplus estimates, Table 1 figures were developed based on summer month spill records excluding actual secondary sales.[1] These years showed considerable variability in water conditions. Overall, 2017 and 2020 were higher water years for Aishihik, and 2021 was a higher water year for Whitehorse. Therefore, Table 1 shows higher summer surplus energy volume for those years. Lower water availability in 2018 and 2019 accounts for lower summer surplus energy volume for those years.

Table 2 on forecast conditions for 2024 and 2035 – energy generation is forecast based on LTA water and other renewable resource availability, with no forecast secondary sales. The increases in summer surplus energy volumes for 2024 and 2035 load cases are predominantly due to added renewable energy options, including IPPs, which lead to increased spills of YEC hydro generation capability. JM-YEC-1-12(a) provides a figure showing estimated summer surplus energy for 2030.

[1] In summary, the recorded spill was limited only to amounts that could have been used for electricity generation given the existing hydro generation capability.

Table 1: 2017-2021 YEC Actual Generation

	Month	Hydro	YEC Wind	IPPs	Thermal	Total Firm Generation	Secondary Sales Generation	Total Generation	Generatable Summer Surplus Energy
		[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
2017	January	46.47	0.00	0.00	2.70	49.18	0.38	49.56	0.00
	February	38.33	0.00	0.00	1.79	40.12	0.98	41.10	0.00
	March	39.81	0.00	0.00	2.46	42.27	0.05	42.32	0.00
	April	33.73	0.00	0.00	0.02	33.75	1.00	34.75	0.00
	May	33.12	0.03	0.00	0.11	33.26	1.06	34.32	0.41
	June	28.39	0.00	0.00	0.16	28.55	0.81	29.36	9.10
	July	28.50	0.00	0.00	0.13	28.63	1.21	29.84	2.57
	August	29.67	0.00	0.00	0.22	29.90	0.84	30.73	11.26
	September	27.73	0.00	0.00	0.66	28.39	0.80	29.20	14.86
	October	38.25	0.00	0.00	0.06	38.31	0.59	38.91	2.18
	November	45.02	0.00	0.00	1.46	46.48	0.89	47.37	0.10
	December	42.93	0.00	0.00	4.70	47.63	0.48	48.11	0.00
	Total	**431.95**	**0.03**	**0.00**	**14.47**	**446.46**	**9.09**	**455.55**	**40.48**
2018	January	44.91	0.00	0.00	5.54	50.46	0.00	50.46	0.00
	February	40.27	0.00	0.00	7.09	47.36	0.00	47.36	0.00
	March	34.43	0.00	0.00	6.33	40.76	0.00	40.76	0.00
	April	33.85	0.00	0.00	5.69	39.55	0.00	39.55	0.00
	May	28.32	0.00	0.00	1.13	29.45	0.00	29.45	0.14
	June	29.98	0.00	0.00	0.41	30.39	0.02	30.40	3.36
	July	29.54	0.00	0.00	0.34	29.89	0.02	29.91	4.82
	August	31.39	0.00	0.00	0.09	31.49	0.16	31.65	2.18
	September	29.66	0.00	0.00	0.01	29.67	0.08	29.75	1.16
	October	35.78	0.00	0.00	1.93	37.71	0.00	37.72	1.26
	November	36.23	0.00	0.00	2.80	39.02	0.00	39.02	0.00
	December	38.40	0.00	0.00	5.94	44.34	0.00	44.34	0.00
	Total	**412.77**	**0.00**	**0.00**	**37.32**	**450.09**	**0.28**	**450.37**	**12.93**
2019	January	40.21	0.00	0.00	7.56	47.77	0.00	47.77	0.00
	February	36.99	0.00	0.00	7.44	44.43	0.00	44.43	0.00
	March	27.22	0.00	0.00	8.57	35.78	0.00	35.79	0.00
	April	25.04	0.00	0.00	9.61	34.65	0.00	34.65	0.00
	May	20.97	0.00	0.00	7.71	28.68	0.00	28.68	0.11
	June	24.57	0.00	0.00	1.41	25.97	0.00	25.97	4.65
	July	29.22	0.00	0.00	0.16	29.38	0.00	29.38	3.48
	August	29.01	0.00	0.00	0.06	29.07	0.00	29.07	1.59
	September	31.02	0.00	0.00	1.02	32.04	0.00	32.04	0.83
	October	32.81	0.00	0.00	7.29	40.10	0.00	40.10	0.28
	November	33.41	0.00	0.00	8.75	42.16	0.00	42.16	0.00
	December	40.35	0.00	0.00	10.29	50.64	0.00	50.64	0.00
	Total	**370.82**	**0.00**	**0.00**	**69.86**	**440.68**	**0.00**	**440.68**	**10.93**
2020	January	41.51	0.00	0.00	17.15	58.66	0.00	58.66	0.00
	February	38.49	0.00	0.00	9.80	48.29	0.00	48.29	0.00
	March	35.11	0.00	0.00	11.98	47.09	0.00	47.09	0.00
	April	27.79	0.00	0.00	11.51	39.29	0.00	39.29	0.00
	May	27.67	0.00	0.00	5.10	32.77	0.00	32.77	0.31
	June	30.99	0.00	0.00	1.13	32.12	0.00	32.12	0.12
	July	33.14	0.00	0.00	0.04	33.18	0.00	33.18	0.38
	August	33.10	0.00	0.00	0.05	33.14	0.00	33.14	4.68
	September	32.06	0.00	0.00	0.98	33.03	0.00	33.03	15.15
	October	41.21	0.00	0.00	0.61	41.82	0.66	42.47	6.77
	November	47.78	0.00	0.00	4.96	52.74	0.00	52.74	0.08
	December	46.53	0.00	0.00	6.13	52.66	-0.46	52.20	0.00
	Total	**435.36**	**0.00**	**0.00**	**69.44**	**504.79**	**0.19**	**504.98**	**27.48**
2021	January	43.65	0.00	0.00	5.00	48.65	0.00	48.65	0.00
	February	47.38	0.00	0.00	10.64	58.02	0.00	58.02	0.00
	March	47.91	0.00	0.00	0.88	48.79	0.00	48.79	0.00
	April	41.75	0.00	0.00	1.17	42.92	0.00	42.92	0.00
	May	34.22	0.00	0.00	0.60	34.82	0.00	34.82	6.46
	June	34.82	0.00	0.00	0.02	34.84	2.12	36.97	4.77
	July	31.63	0.00	0.00	0.15	31.79	0.46	32.25	11.67
	August	35.63	0.00	0.00	0.48	36.11	0.41	36.52	7.53
	September	33.95	0.00	0.00	0.36	34.30	0.28	34.58	5.41
	October	41.87	0.00	0.00	0.74	42.62	0.96	43.58	2.79
	November	46.55	0.00	0.00	5.60	52.15	0.74	52.89	0.00
	December	48.76	0.00	0.00	13.57	62.34	0.13	62.47	0.00
	Total	**488.13**	**0.00**	**0.00**	**39.22**	**527.35**	**5.11**	**532.46**	**38.61**

Table 2: 2024 and 2035 Forecast Generation

	Month	LTA Hydro	Atlin [net of losses]	Total IPPs and Incremental Microgen	LTA Thermal	Total Firm Generation	Summer Surplus Renewable Generation
		[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
2024	January	39.19	5.47	4.33	2.07	51.07	0.00
	February	36.70	4.98	3.45	2.12	47.25	0.00
	March	38.48	3.60	3.53	3.24	48.85	0.00
	April	33.36	1.49	3.24	3.33	41.41	0.00
	May	31.90	2.09	4.13	1.17	39.29	1.35
	June	33.77	0.00	2.50	0.08	36.35	4.97
	July	34.73	0.00	2.24	0.09	37.06	8.79
	August	33.79	0.00	3.80	0.00	37.59	10.53
	September	33.29	2.51	3.13	0.01	38.94	11.13
	October	41.23	1.98	3.01	0.21	46.43	3.16
	November	44.01	2.56	3.38	1.11	51.06	0.01
	December	42.87	4.18	3.19	2.32	52.56	0.00
	Total	**443.31**	**28.85**	**39.93**	**15.76**	**527.85**	**39.94**
2035	January	40.63	5.47	4.33	0.69	51.13	0.00
	February	37.68	4.98	3.45	1.04	47.16	0.00
	March	36.40	3.60	3.53	1.14	44.67	0.00
	April	30.88	1.49	3.24	1.15	36.75	0.00
	May	27.93	2.09	4.13	0.18	34.33	3.79
	June	28.50	0.00	2.50	0.00	31.00	10.83
	July	29.51	0.00	2.24	0.00	31.75	14.90
	August	28.52	0.00	3.80	0.00	32.32	16.95
	September	27.92	2.51	3.13	0.00	33.56	18.20
	October	36.55	1.98	3.01	0.00	41.54	5.97
	November	40.38	2.56	3.38	0.02	46.34	0.06
	December	44.84	4.18	3.19	0.30	52.52	0.00
	Total	**409.75**	**28.85**	**39.93**	**4.53**	**483.07**	**70.70**

	Month	LTA Hydro	Atlin [net of losses]	Total IPPs and Incremental Microgen	LTA Thermal	Total Firm Generation	Summer Surplus Renewable Generation
		[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
2024	January	39.08	6.22	4.33	1.44	51.07	0.00
	February	36.55	5.62	3.45	1.63	47.25	0.00
	March	38.39	4.29	3.53	2.63	48.85	0.00
	April	35.18	0.25	3.24	2.75	41.41	0.00
	May	32.21	2.25	4.13	0.70	39.29	0.88
	June	33.77	0.00	2.50	0.08	36.35	5.10
	July	34.78	0.00	2.24	0.03	37.06	8.97
	August	33.79	0.00	3.80	0.00	37.59	10.89
	September	35.80	0.00	3.13	0.01	38.94	9.66
	October	41.56	1.76	3.01	0.09	46.43	2.95
	November	41.01	6.02	3.38	0.66	51.06	0.03
	December	42.22	6.02	3.19	1.13	52.56	0.00
	Total	**444.34**	**32.42**	**39.93**	**11.16**	**527.85**	**38.48**

2035	January	40.33	6.22	4.33	0.25	51.13	0.00
	February	37.72	5.62	3.45	0.37	47.16	0.00
	March	36.17	4.29	3.53	0.68	44.67	0.00
	April	32.40	0.25	3.24	0.86	36.75	0.02
	May	27.90	2.25	4.13	0.05	34.33	2.92
	June	28.50	0.00	2.50	0.00	31.00	11.72
	July	29.51	0.00	2.24	0.00	31.75	15.90
	August	28.52	0.00	3.80	0.00	32.32	17.55
	September	30.43	0.00	3.13	0.00	33.56	16.88
	October	36.77	1.76	3.01	0.00	41.54	6.01
	November	36.94	6.02	3.38	0.01	46.34	0.22
	December	43.25	6.02	3.19	0.07	52.52	0.00
	Total	**408.43**	**32.42**	**39.93**	**2.28**	**483.07**	**71.21**

See Table A3-1 in the Submission for annual summaries. Atlin LTA winter deliveries to Jakes Corner are 34.0-8 GWh (row 1 in Table A3-1); Atlin deliveries for LTA thermal displacement assessments with YECSIM assume 6.24.5% 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 $2400~~06~~ 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~~90 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

	No Grant	With Grant
With Annual Energy		
Project LCOE ($/kWh)	$0.287	$0.141
Project LCOC ($/MW)	$1,339,482	$645,163
With LTA Thermal Displaced Energy		
Project LCOE ($/kWh)	$0.490	$0.238
Project LCOC ($/MW)	$1,339,482	$645,163

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 $240~~06~~ million [2024$].
2. Grant amount assumed at $150 million [2024$].
3. Fixed O&M at $2.0 million/year [2024$] – reflects approximately 0.8~~1~~% of hydro generation plant $~~206~~170 million 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 8.75 MW.
6. Annual energy at 41.5~~736.2~~ GWh and LTA thermal displacement benefits at 24.2~~19.6~~ GWh.
7. Weighted Average Cost of Capital at 4.~~75~~9% (YEC 2021 GRA Compliance Filing 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 41.5736.2 GWh of energy annually on a long-term basis, only 24.219.6 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 24.219.6 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 17.35 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)

The following responses assume 8.75 MW delivered at Jakes Corner – where it makes a difference, brackets show the response assuming 8.5 MW delivered at Jakes Corner:

i. Jake's Corner (JC) towards Teslin: 2.452 MW at JC side
Jake's Corner towards Whitehorse: ~6.25 MW [~6 MW] with only ~~1.90~~ 2.06 MW [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~~ 2.10 MW [1.945 MW] through MacRae towards Whitehorse S150

iv. From Jake's Corner: ~~1.90~~ 2.06 MW [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 24.2~~19.6~~ GWh for 2024). Principle #3 then states that YEC purchases all available winter energy that THELP provides (LTA deliveries of 34.0~~0.8~~ GWh).

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

- LTA displacement in 2024 equals only approximately 71.2~~63.5~~% of LTA deliveries.

- The average energy price paid of all energy delivered is then set at 71.2~~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. 34.0~~0.8~~ 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 the 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 12.91.7% * 14.2 / 33.950.8]. This rate is applied to energy delivered (34.00.8 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**

1

	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**

2

	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**

3

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.135	0.136	0.138	0.139	0.140	0.142	0.143	0.145	0.146	0.148	0.149
Energy Payment, $million	4.583	4.629	4.675	4.722	4.769	4.817	4.865	4.914	4.963	5.013	5.063
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	1.750	1.785	1.821	1.857	1.894	1.932	1.971	2.010	2.050	2.091	2.133
Total Payment, $million	**6.333**	**6.414**	**6.496**	**6.579**	**6.664**	**6.749**	**6.836**	**6.924**	**7.013**	**7.104**	**7.196**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.108	0.109	0.110	0.111	0.113	0.114	0.115	0.116	0.117	0.118	0.120
Energy Payment, $million	3.674	3.711	3.748	3.785	3.823	3.861	3.900	3.939	3.978	4.018	4.058
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		0.014	0.030	0.045	0.062	0.079	0.096	0.115	0.134	0.153	0.174
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.176	2.219	2.264	2.309	2.355	2.402	2.450	2.499	2.549	2.600	2.652
Total Payment, $million	**5.850**	**5.945**	**6.041**	**6.140**	**6.240**	**6.342**	**6.447**	**6.553**	**6.661**	**6.772**	**6.885**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.121	0.122	0.123	0.124	0.126	0.127	0.128	0.129	0.131	0.132
Energy Payment, $million	4.099	4.140	4.181	4.223	4.265	4.308	4.351	4.395	4.439	4.483
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	0.195	0.217	0.240	0.264	0.289	0.314	0.341	0.369	0.397	0.427
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.705	2.760	2.815	2.871	2.928	2.987	3.047	3.108	3.170	3.233
Total Payment, $million	**7.000**	**7.117**	**7.237**	**7.358**	**7.483**	**7.610**	**7.739**	**7.871**	**8.006**	**8.143**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Energy Payment, $million	4.528	4.573	4.619	4.665	4.712	4.759	4.806	4.855	4.903	4.952
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	0.457	0.489	0.521	0.555	0.590	0.627	0.664	0.703	0.743	0.785
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	3.298	3.364	3.431	3.500	3.570	3.641	3.714	3.788	3.864	3.941
Total Payment, $million	**8.283**	**8.426**	**8.572**	**8.720**	**8.872**	**9.027**	**9.185**	**9.346**	**9.510**	**9.678**

(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**

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.135	0.136	0.138	0.139	0.140	0.142	0.143	0.145	0.146	0.148	0.149
Energy Payment, $million	4.583	4.629	4.675	4.722	4.769	4.817	4.865	4.914	4.963	5.013	5.063
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	1.750	1.785	1.821	1.857	1.894	1.932	1.971	2.010	2.050	2.091	2.133
Total Payment, $million	**6.333**	**6.414**	**6.496**	**6.579**	**6.664**	**6.749**	**6.836**	**6.924**	**7.013**	**7.104**	**7.196**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.108	0.109	0.110	0.111	0.113	0.114	0.115	0.116	0.117	0.118	0.120
Energy Payment, $million	3.674	3.711	3.748	3.785	3.823	3.861	3.900	3.939	3.978	4.018	4.058
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		1.339	1.380	1.423	1.467	1.512	1.558	1.606	1.655	1.705	0.174
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.176	2.219	2.264	2.309	2.355	2.402	2.450	2.499	2.549	2.600	2.652
Total Payment, $million	**5.850**	**7.269**	**7.392**	**7.517**	**7.645**	**7.776**	**7.909**	**8.044**	**8.183**	**8.324**	**6.885**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.121	0.122	0.123	0.124	0.126	0.127	0.128	0.129	0.131	0.132
Energy Payment, $million	4.099	4.140	4.181	4.223	4.265	4.308	4.351	4.395	4.439	4.483
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	0.195	0.217	0.240	0.264	0.289	0.314	0.341	0.369	0.397	0.427
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.705	2.760	2.815	2.871	2.928	2.987	3.047	3.108	3.170	3.233
Total Payment, $million	**7.000**	**7.117**	**7.237**	**7.358**	**7.483**	**7.610**	**7.739**	**7.871**	**8.006**	**8.143**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Energy Payment, $million	4.528	4.573	4.619	4.665	4.712	4.759	4.806	4.855	4.903	4.952
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	0.457	0.489	0.521	0.555	0.590	0.627	0.664	0.703	0.743	0.785
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	3.298	3.364	3.431	3.500	3.570	3.641	3.714	3.788	3.864	3.941
Total Payment, $million	**8.283**	**8.426**	**8.572**	**8.720**	**8.872**	**9.027**	**9.185**	**9.346**	**9.510**	**9.678**

In the above examples the added winter load remains below the max 68 GWh. As illustrated in the example provided in response to JM-YEC-1-16, the added winter load for 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.

REVISED RESPONSE

(d)

On March 14, 2022, Mr. Maissan by email correspondence to the Board requested further information regarding this response, noting that "the LCOE that YEC would be paying over the 40-year term of this agreement is quite relevant to customer rates over this period of time, and that it would be imprudent not to examine all such aspects of the Agreement before coming to a conclusion as to its prudency for Yukon ratepayers." Mr. Maissan requested that YEC provide further information.

On further review, YEC understands that Mr. Maissan is asking for the levelized cost of each kWh delivered over the EPA term, based on EPA payments estimated in responses to the cases provided in questions (a) through (c). Table A at the end of this response summarizes the 2024 to 2065 annual results from tables provided in (a) and (b) showing annual EPA winter energy deliveries, annual total EPA costs to YEC (energy and capacity payments), and resulting YEC costs per kWh delivered for each year.

Using the stream of annual payments from Table A, the table below calculates the present value of the payments using YEC real weighted average cost of capital (WACC)[1]. Dividing this total by the present value of total energy deliveries provides the LCOE totals in row two of the table.

	Option under JM-YEC-1-10 a)	Option under JM-YEC-1-10 b)
PV of Energy and Capacity Payments, $ millions	$112.82	$118.36
LCOE based on EPA Payments ($/kWh), 2024$	$0.144	$0.151

[1] Assumed at 2.~~75~~54%, based on nominal WACC of 4.~~75~~59% (2021 GRA Compliance F~~f~~iling) and assumed inflation of 2%/year

	Option under JM-YEC-1-10 a)	Option under JM-YEC-1-10 b)
PV of Energy and Capacity Payments, $ millions	$134.23	$140.53
LCOE based on EPA Payments ($/kWh), 2024$	$0.166	$0.174

No separate calculation is prepared for (c) as the LCOE would be same as calculated for (a); that is, the cost of EPA energy for the period 2029-2034 is the same under options (a) and (c).

In the original response YEC had noted that the EPA energy pricing is not based on LCOE, but based on LTA thermal displacement benefits [i.e., YEC does not pay the energy rate based on Project LCOE]. The EPA energy pricing approach directly addresses prudence of this pricing by linking it to estimated LTA thermal fuel costs saved and estimated thermal dependable capacity costs saved [based on a levelized cost of capital calculation].

Levelized cost assessments normally are based on a project's total capital and O&M costs and its total annual energy generation capability (i.e., all months) over its life. EPA pricing for the Atlin Hydro Expansion Project, however, is not based on THELP costs for the project, using instead estimated costs of displaced LTA thermal fuel applied against project energy deliveries during only the defined winter period as well as dependable capacity payments based on dependable capacity to be provided by the Project.

Table A: Summary of Results from JM-YEC-1-10(a) andJM-YEC-1-10(b)

	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
Option under JM-YEC-!-10(a)											
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
Average $ per kWh [incl. capacity payment]	0.173	0.175	0.178	0.180	0.182	0.185	0.187	0.190	0.192	0.195	0.197
YUB Thermal Fuel Price $/kWh	0.190	0.194	0.198	0.202	0.206	0.210	0.214	0.218	0.223	0.227	0.232
Option under JM-YEC-!-10(b)											
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
Average $ per kWh [incl. capacity payment]	0.173	0.175	0.178	0.180	0.182	0.185	0.187	0.190	0.192	0.195	0.197
YUB Thermal Fuel Price $/kWh	0.190	0.194	0.198	0.202	0.206	0.210	0.214	0.218	0.223	0.227	0.232

	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
Option under JM-YEC-!-10(a)											
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
Average $ per kWh [incl. capacity payment]	0.168	0.171	0.173	0.176	0.179	0.182	0.185	0.188	0.191	0.195	0.198
YUB Thermal Fuel Price $/kWh	0.236	0.241	0.246	0.251	0.256	0.261	0.266	0.271	0.277	0.282	0.288
Option under JM-YEC-!-10(b)											
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
Average $ per kWh [incl. capacity payment]	0.168	0.210	0.213	0.217	0.221	0.224	0.228	0.232	0.236	0.240	0.198
YUB Thermal Fuel Price $/kWh	0.236	0.241	0.246	0.251	0.256	0.261	0.266	0.271	0.277	0.282	0.288

	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
Option under JM-YEC-!-10(a)										
Total Payment, $million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214
Average $ per kWh [incl. capacity payment]	0.201	0.205	0.208	0.212	0.215	0.219	0.223	0.227	0.231	0.235
YUB Thermal Fuel Price $/kWh	0.294	0.300	0.306	0.312	0.318	0.324	0.331	0.337	0.344	0.351
Option under JM-YEC-!-10(b)										
Total Payment, $million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214
Average $ per kWh [incl. capacity payment]	0.201	0.205	0.208	0.212	0.215	0.219	0.223	0.227	0.231	0.235
YUB Thermal Fuel Price $/kWh	0.294	0.300	0.306	0.312	0.318	0.324	0.331	0.337	0.344	0.351

	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
Option under JM-YEC-!-10(a)										
Total Payment, $million	7.340	7.468	7.599	7.732	7.868	8.007	8.149	8.293	8.441	8.592
Average $ per kWh [incl. capacity payment]	0.239	0.243	0.247	0.251	0.256	0.260	0.265	0.270	0.274	0.279
YUB Thermal Fuel Price $/kWh	0.358	0.365	0.373	0.380	0.388	0.395	0.403	0.411	0.420	0.428
Option under JM-YEC-!-10(b)										
Total Payment, $million	7.340	7.468	7.599	7.732	7.868	8.007	8.149	8.293	8.441	8.592
Average $ per kWh [incl. capacity payment]	0.239	0.243	0.247	0.251	0.256	0.260	0.265	0.270	0.274	0.279
YUB Thermal Fuel Price $/kWh	0.358	0.365	0.373	0.380	0.388	0.395	0.403	0.411	0.420	0.428

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Under JM-YEC-1-10 (a)											
Total Payments, $million	6.333	6.414	6.496	6.579	6.664	6.749	6.836	6.924	7.013	7.104	7.196
Average $ per kWh [incl. capacity payment]	*0.187*	*0.189*	*0.191*	*0.194*	*0.196*	*0.199*	*0.201*	*0.204*	*0.207*	*0.209*	*0.212*
YUB Thermal Fuel Price $/kWh	*0.190*	*0.194*	*0.198*	*0.202*	*0.206*	*0.210*	*0.214*	*0.218*	*0.223*	*0.227*	*0.232*
Under JM-YEC-1-10 (b)											
Total Payments, $million	6.333	6.414	6.496	6.579	6.664	6.749	6.836	6.924	7.013	7.104	7.196
Average $ per kWh [incl. capacity payment]	*0.187*	*0.189*	*0.191*	*0.194*	*0.196*	*0.199*	*0.201*	*0.204*	*0.207*	*0.209*	*0.212*
YUB Thermal Fuel Price $/kWh	*0.190*	*0.194*	*0.198*	*0.202*	*0.206*	*0.210*	*0.214*	*0.218*	*0.223*	*0.227*	*0.232*

	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
Option under JM-YEC-!-10(a)											
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
Average $ per kWh [incl. capacity payment]	0.173	0.175	0.178	0.180	0.182	0.185	0.187	0.190	0.192	0.195	0.197
YUB Thermal Fuel Price $/kWh	0.190	0.194	0.198	0.202	0.206	0.210	0.214	0.218	0.223	0.227	0.232
Option under JM-YEC-!-10(b)											
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
Average $ per kWh [incl. capacity payment]	0.173	0.175	0.178	0.180	0.182	0.185	0.187	0.190	0.192	0.195	0.197
YUB Thermal Fuel Price $/kWh	0.190	0.194	0.198	0.202	0.206	0.210	0.214	0.218	0.223	0.227	0.232

	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
Option under JM-YEC-!-10(a)											
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
Average $ per kWh [incl. capacity payment]	0.168	0.171	0.173	0.176	0.179	0.182	0.185	0.188	0.191	0.195	0.198
YUB Thermal Fuel Price $/kWh	0.236	0.241	0.246	0.251	0.256	0.261	0.266	0.271	0.277	0.282	0.288
Option under JM-YEC-!-10(b)											
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
Average $ per kWh [incl. capacity payment]	0.168	0.210	0.213	0.217	0.221	0.224	0.228	0.232	0.236	0.240	0.198
YUB Thermal Fuel Price $/kWh	0.236	0.241	0.246	0.251	0.256	0.261	0.266	0.271	0.277	0.282	0.288

	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
Option under JM-YEC-!-10(a)										
Total Payment, $million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214
Average $ per kWh [incl. capacity payment]	0.201	0.205	0.208	0.212	0.215	0.219	0.223	0.227	0.231	0.235
YUB Thermal Fuel Price $/kWh	0.294	0.300	0.306	0.312	0.318	0.324	0.331	0.337	0.344	0.351
Option under JM-YEC-!-10(b)										
Total Payment, $million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214
Average $ per kWh [incl. capacity payment]	0.201	0.205	0.208	0.212	0.215	0.219	0.223	0.227	0.231	0.235
YUB Thermal Fuel Price $/kWh	0.294	0.300	0.306	0.312	0.318	0.324	0.331	0.337	0.344	0.351

	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
Option under JM-YEC-!-10(a)										
Total Payment, $million	7.340	7.468	7.599	7.732	7.868	8.007	8.149	8.293	8.441	8.592
Average $ per kWh [incl. capacity payment]	0.239	0.243	0.247	0.251	0.256	0.260	0.265	0.270	0.274	0.279
YUB Thermal Fuel Price $/kWh	0.358	0.365	0.373	0.380	0.388	0.395	0.403	0.411	0.420	0.428
Option under JM-YEC-!-10(b)										
Total Payment, $million	7.340	7.468	7.599	7.732	7.868	8.007	8.149	8.293	8.441	8.592
Average $ per kWh [incl. capacity payment]	0.239	0.243	0.247	0.251	0.256	0.260	0.265	0.270	0.274	0.279
YUB Thermal Fuel Price $/kWh	0.358	0.365	0.373	0.380	0.388	0.395	0.403	0.411	0.420	0.428

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Under JM-YEC-1-10 (a)											
Total Payments, $million	5.850	5.945	6.041	6.140	6.240	6.342	6.447	6.553	6.661	6.772	6.885
Average $ per kWh [incl. capacity payment]	*0.172*	*0.175*	*0.178*	*0.181*	*0.184*	*0.187*	*0.190*	*0.193*	*0.196*	*0.199*	*0.203*
YUB Thermal Fuel Price $/kWh	*0.236*	*0.241*	*0.246*	*0.251*	*0.256*	*0.261*	*0.266*	*0.271*	*0.277*	*0.282*	*0.288*
Under JM-YEC-1-10 (b)											
Total Payments, $million	5.850	7.269	7.392	7.517	7.645	7.776	7.909	8.044	8.183	8.324	6.885
Average $ per kWh [incl. capacity payment]	*0.172*	*0.214*	*0.218*	*0.221*	*0.225*	*0.229*	*0.233*	*0.237*	*0.241*	*0.245*	*0.203*
YUB Thermal Fuel Price $/kWh	*0.236*	*0.241*	*0.246*	*0.251*	*0.256*	*0.261*	*0.266*	*0.271*	*0.277*	*0.282*	*0.288*

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Under JM-YEC-1-10 (a)										
Total Payments, $million	7.000	7.117	7.237	7.358	7.483	7.610	7.739	7.871	8.006	8.143
Average $ per kWh [incl. capacity payment]	*0.206*	*0.210*	*0.213*	*0.217*	*0.220*	*0.224*	*0.228*	*0.232*	*0.236*	*0.240*
YUB Thermal Fuel Price $/kWh	*0.294*	*0.300*	*0.306*	*0.312*	*0.318*	*0.324*	*0.331*	*0.337*	*0.344*	*0.351*
Under JM-YEC-1-10 (b)										
Total Payments, $million	7.000	7.117	7.237	7.358	7.483	7.610	7.739	7.871	8.006	8.143
Average $ per kWh [incl. capacity payment]	*0.206*	*0.210*	*0.213*	*0.217*	*0.220*	*0.224*	*0.228*	*0.232*	*0.236*	*0.240*
YUB Thermal Fuel Price $/kWh	*0.294*	*0.300*	*0.306*	*0.312*	*0.318*	*0.324*	*0.331*	*0.337*	*0.344*	*0.351*

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Under JM-YEC-1-10 (a)										
Total Payments, $million	8.283	8.426	8.572	8.720	8.872	9.027	9.185	9.346	9.510	9.678
Average $ per kWh [incl. capacity payment]	*0.244*	*0.248*	*0.252*	*0.257*	*0.261*	*0.266*	*0.271*	*0.275*	*0.280*	*0.285*
YUB Thermal Fuel Price $/kWh	*0.358*	*0.365*	*0.373*	*0.380*	*0.388*	*0.395*	*0.403*	*0.411*	*0.420*	*0.428*
Under JM-YEC-1-10 (b)										
Total Payments, $million	8.283	8.426	8.572	8.720	8.872	9.027	9.185	9.346	9.510	9.678
Average $ per kWh [incl. capacity payment]	*0.244*	*0.248*	*0.252*	*0.257*	*0.261*	*0.266*	*0.271*	*0.275*	*0.280*	*0.285*
YUB Thermal Fuel Price $/kWh	*0.358*	*0.365*	*0.373*	*0.380*	*0.388*	*0.395*	*0.403*	*0.411*	*0.420*	*0.428*

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**

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.135	0.136	0.138	0.139	0.140	0.142	0.143	0.145	0.146	0.148	0.149
Energy Payment, $million	4.583	4.629	4.675	4.722	4.769	4.817	4.865	4.914	4.963	5.013	5.063
Added Winter Load, GWh											
Added Load Rate [YUB price $0.19/kWh]											
Added Load Rate Payment, $m											
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	1.750	1.785	1.821	1.857	1.894	1.932	1.971	2.010	2.050	2.091	2.133
Total Payment, $million	**6.333**	**6.414**	**6.496**	**6.579**	**6.664**	**6.749**	**6.836**	**6.924**	**7.013**	**7.104**	**7.196**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.108	0.109	0.110	0.111	0.113	0.114	0.115	0.116	0.117	0.118	0.120
Energy Payment, $million	3.674	3.711	3.748	3.785	3.823	3.861	3.900	3.939	3.978	4.018	4.058
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		0.181	0.372	0.573	0.785	1.009	1.244	1.492	1.752	2.026	2.314
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.176	2.219	2.264	2.309	2.355	2.402	2.450	2.499	2.549	2.600	2.652
Total Payment, $million	**5.850**	**6.111**	**6.384**	**6.668**	**6.964**	**7.273**	**7.595**	**7.930**	**8.280**	**8.645**	**9.025**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.121	0.122	0.123	0.124	0.126	0.127	0.128	0.129	0.131	0.132
Energy Payment, $million	4.099	4.140	4.181	4.223	4.265	4.308	4.351	4.395	4.439	4.483
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	0.085	0.087	0.089	0.091
Added Load Rate Payment, $m	2.577	2.628	2.681	2.734	2.789	2.845	2.902	2.960	3.019	3.079
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.705	2.760	2.815	2.871	2.928	2.987	3.047	3.108	3.170	3.233
Total Payment, $million	**9.381**	**9.528**	**9.677**	**9.829**	**9.983**	**10.140**	**10.300**	**10.462**	**10.628**	**10.796**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Energy Payment, $million	4.528	4.573	4.619	4.665	4.712	4.759	4.806	4.855	4.903	4.952
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	0.108	0.111
Added Load Rate Payment, $m	3.141	3.204	3.268	3.333	3.400	3.468	3.537	3.608	3.680	3.754
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	3.298	3.364	3.431	3.500	3.570	3.641	3.714	3.788	3.864	3.941
Total Payment, $million	**10.967**	**11.141**	**11.318**	**11.498**	**11.681**	**11.868**	**12.058**	**12.251**	**12.447**	**12.647**

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.108	0.109	0.110	0.111	0.113	0.114	0.115	0.116	0.117	0.118	0.120
Energy Payment, $million	3.674	3.711	3.748	3.785	3.823	3.861	3.900	3.939	3.978	4.018	4.058
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		0.181	0.372	0.573	0.785	1.009	1.244	1.492	1.752	2.026	2.314
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.176	2.219	2.264	2.309	2.355	2.402	2.450	2.499	2.549	2.600	2.652
Total Payment, $million	**5.850**	**6.111**	**6.384**	**6.668**	**6.964**	**7.273**	**7.595**	**7.930**	**8.280**	**8.645**	**9.025**

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.121	0.122	0.123	0.124	0.126	0.127	0.128	0.129	0.131	0.132
Energy Payment, $million	4.099	4.140	4.181	4.223	4.265	4.308	4.351	4.395	4.439	4.483
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	0.085	0.087	0.089	0.091
Added Load Rate Payment, $m	2.577	2.628	2.681	2.734	2.789	2.845	2.902	2.960	3.019	3.079
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	2.705	2.760	2.815	2.871	2.928	2.987	3.047	3.108	3.170	3.233
Total Payment, $million	**9.381**	**9.528**	**9.677**	**9.829**	**9.983**	**10.140**	**10.300**	**10.462**	**10.628**	**10.796**

	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Energy Price, $/kWh	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
Energy Payment, $million	4.528	4.573	4.619	4.665	4.712	4.759	4.806	4.855	4.903	4.952
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	0.108	0.111
Added Load Rate Payment, $m	3.141	3.204	3.268	3.333	3.400	3.468	3.537	3.608	3.680	3.754
Dependable Capacity, MW	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75
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	3.298	3.364	3.431	3.500	3.570	3.641	3.714	3.788	3.864	3.941
Total Payment, $million	**10.967**	**11.141**	**11.318**	**11.498**	**11.681**	**11.868**	**12.058**	**12.251**	**12.447**	**12.647**

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 May~~rch~~ 31, 2022.

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 Notice~~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 has been corrected in the Amended EPA as shown in the revised PREAMBLE quote above. ~~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:~~

~~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.~~

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

~~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 8.5 MW to 8.75 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 8.5 and 8.75 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 8,7500 kW that is confirmed at the final commercial operation date [COD] for Seller's Plant [therefore, the 8.75 MW is a cap, but this result during COD could be less than the 8.5 MW minimum required at COD], 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 8.5 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)

This has been corrected in the Amended EPA~~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 has ~~been~~ been corrected in the Amended EPA. ~~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 A1-66 EXHIBIT B-1**

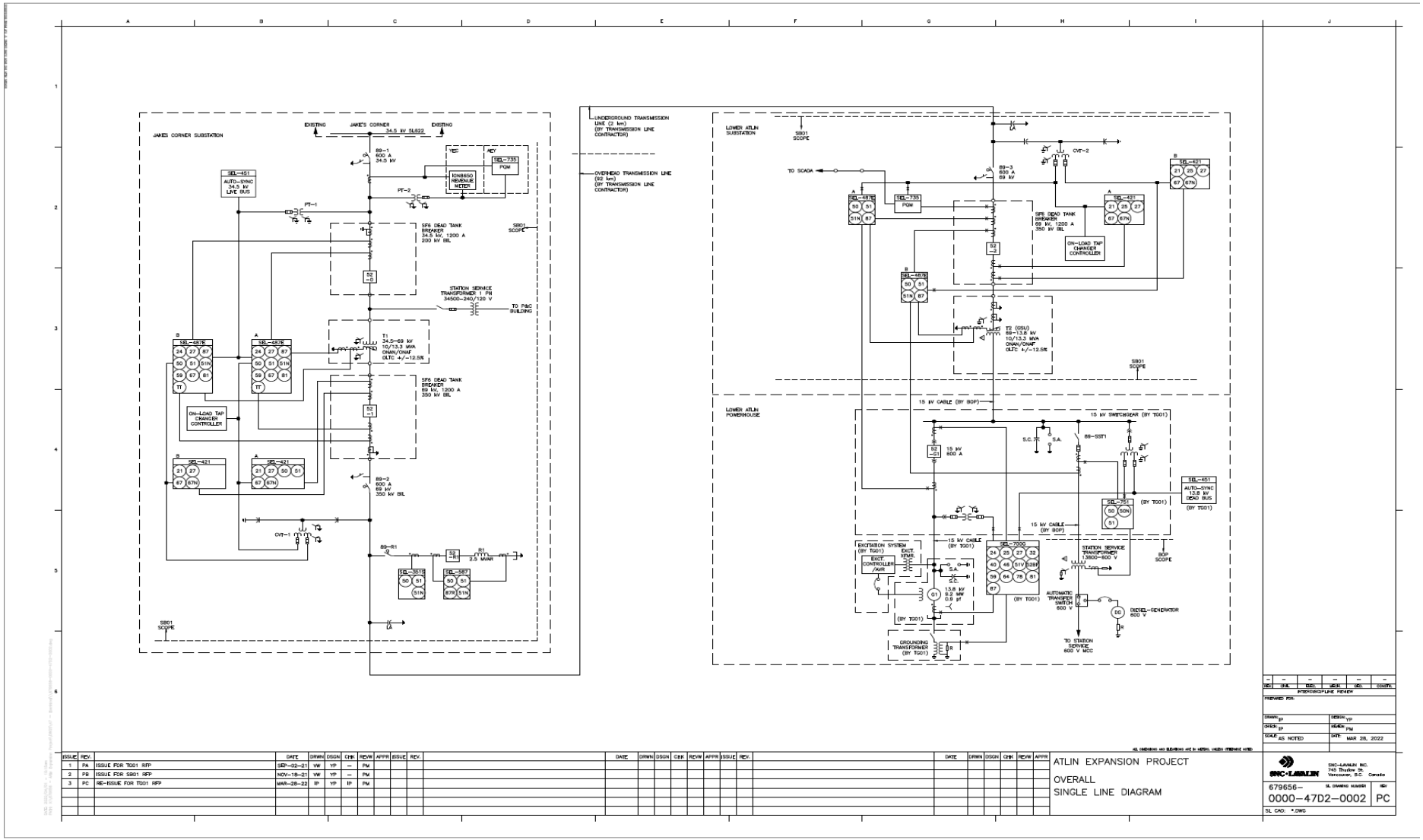
QUESTION:

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

ANSWER:

(a)

Please see page 2~~Attachment 1~~ to this response.


JAKES CORNER SUBSTATION
LOWER ATLIN SUBSTATION
LOWER ATLIN POWERHOUSE
ATLIN EXPANSION PROJECT
OVERALL
SINGLE LINE DIAGRAM
679656-
0000-47D2-0002
PC

1

Utilities Consumers' Group
(UCG)

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

[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 all energy~~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~~. The Amended EPA does not have separate firm and non-firm energy prices. 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.

TOPIC:

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

[41] The $6.45.3 million/year (2024$) until the end of 2034 (and the $5 million thereafter) assumes 8.750 MW dependable capacity ($1.756 million/year) plus 34.00.8 GWh/year winter delivered energy ($4.63.7 million/year for the years to the end of 2034 and $3.3 million for the years thereafter as per Appendix A, Table A3-2). The Project is capable of providing 7.85.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 7.85.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.75 million/year (price at 50% of the approved blended fuel cost).

PREAMBLE:

QUESTION:

a) Is this $6.45.3 million per year total cost ($1.756 million dependable capacity plus $4.63.7 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).

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 8.750 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 34.00.8 GWh that is expected to displace between 17.35.0 and 24.219.6 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: **Project description**

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

QUOTE: "The Project is an 9.38.7 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 5135 modeled water years (Appendix A, Table A12) assuming forecast Atlin BC Hydro load with battery for 2032 at 7.116.93 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 51 modeled35 water years would equal at least 14 GWh and be sufficient to enable a full 8.750 MW of capacity to be delivered to YEC at Jakes Corner for

more than 85% ~~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 A1~~2~~ of the Submission confirms that the above outcome is expected even when the Surprise Lake reservoir is not full in the prior October/November (based on the ~~one relevant~~ historic water year modeled estimates), so long as the Existing Plant and battery load requirement is at 7.11~~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 8.75~~0~~ MW provided for over 85~~94~~% of the PWP days) is retained regardless of possible Existing Plant and battery 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 and battery load does not exceed 9 GWh/year, water availability is expected to be adequate for LTA delivered energy to YEC during the PWP to be at least 12 GWh, which is sufficient to enable a full 8.75~~0~~ MW of capacity to be delivered at POI for over~~at least~~ 54~~37~~ full days (assuming the~~with~~ balance of PWP days at ~~65~~approximately 11% of 8.75~~0~~ MW), i.e., confirmed ability to accommodate at full capacity at least one two-week cold temperature period plus at least 40~~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) and 7.3 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: **Thermal displacement**

REFERENCE: **Application, page 5, PDF page 8**

QUOTE: "As reviewed in Section 3 below, the Amended 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 34.00.8 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 24.219.6 GWh/year at forecast 2024 YIS load after considering other existing or expected renewable sources."

QUESTION:

a) If 34.00.8 GWh is provided year-round and the thermal displacement is 24.219.6 GWh, what is the cost of the remaining 9.811.2 GWh?

ANSWER:

(a)

The energy cost (price) is based on the LTA delivery of 34.0 GWh per year (with its related annual variability) being estimated to displace 24.2 GWh/year of thermal generation.~~the same for the entire commitment of 30.8 GWh.~~ The unit price is calculated to reflect that not all of this delivered 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) 34.00.8 GWh is for EPA deliveries provided only during the defined Winter Period. It reflects the average deliveries over 5135 modeled

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, subject to the Operating Rules, to take all of the energy deliveries provided during the Winter Period (i.e., the 34.00.8 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 24.219.6 GWh/year of expected thermal displacement from the EPA winter deliveries were therefore estimated to provide YEC cost savings of approximately $4.593.72 million per year (2024$).

- 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 34.00.8 GWh of deliveries equals $0.13521/kWh or $4.593.72 million divided by 34.00.8 GWh.

Table A3-1 of the Submission provides detailed calculations for the average EPA price payable in 2024$ for the 2024 load forecast ($0.13521/kWh) and for the 2035 load forecast ($0.0973/kWh). Table A3-2 of the Submission provides the determination of firm and non-firm winter energy prices (2024$/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 $0.1335~~21~~/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 $240~~06~~ million. Grant funding of approximately $150 million has been committed ~~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 51 modeled~~35~~ water years and the SNC Lavalin analysis (see Section 2.1.3 of the YEC Submission) confirms that water availability is not

[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."

an expected 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 Amended 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 Amended 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 Amended EPA is expected to reduce this capacity shortfall and diesel rental requirement by 8.750~~0~~ MW. Without Moon Lake pumped storage, r~~R~~ented diesel requirements would be forecast to be reduced accordingly (ignoring any additional requirement for spares):
  - In winter 2024/25, from 10~~6~~ units to 5~~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 Amended EPA reflect full delivery during winter months each year based on available water year information for the Atlin project (51 modeled ~~35~~ years) as provided in Table A1 of YEC's Submission. The Amended EPA does not "contract" for THELP to provide any specific minimum annual level of winter energy deliveries (beyond providing what is available each Winter Period, subject to Operating Rules controls and constraints) – and the payment provided for winter energy deliveries each Year will be based on one set price per kWh delivered.

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 Amended EPA energy pricing does not provide a separate~~s~~ a price for "firm" energy deliveries (the first 23.4~~5.2~~ 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 23.4~~5.2~~ 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 51 ~~35~~modeled Atlin water years indicates the following for Atlin water years with deliveries less than 90% of the 34,0~~0.8~~ GWh/year LTA (i.e., below 30.6~~27.7~~ GWh) used in Figure 2-4:

- 4~~2~~ years below 26 GWh (1985~~78~~ at 23.45~~.2~~ GWh, ~~and~~ 1976~~1979~~ at 24.45~~.8~~ GWh, 1973 at 25.5 GWh and 2008 at 25.6 GWh).
- 4~~3~~ years above 26 GWh, and below 27 GWh (2013 and 2020~~1965~~ at 26.105~~5~~ GWh, 2019~~1966~~ at 26.6~~8~~ GWh and 1996~~85~~ at 26.7~~9~~ GWh).
- 3~~1~~ years above 27 GWh, and below 28~~7.7~~ GWh (1978~~3~~ at 27.34~~~~ GWh, 1995 at 27.4GWh and 1993 at 27.9 GWh).
- 3 years between 30.0 and 30.6 GWh (2017 at 30.0 GWh, 1997 at 30.3 GWh and 1990 at 30.6 GWh).

(b)

Low water or drought conditions at Atlin will reduce annual energy deliveries, but are not expected to lower the dependable capacity of 8.75~~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 more than 50 modeled~~35~~ water years ~~of record~~,[1] will~~are expected to~~ enable a full 8.75~~0~~ MW of capacity to be delivered to YEC each year at Jakes Corner for over 85%~~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 A1~~2~~ 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 and battery load is 7.11~~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 $2400~~06~~ 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 $2400~~06~~ million estimate (2024$) for Project capital costs reflects information provided to YEC by THELP in March 2022~~spring 2021~~, with adjustment to reflect the revised Project design and the latest~~late 2021~~ estimates for other costs~~YEC/AEY System Upgrade Costs~~. YEC has not received any detail on the breakdown of these updated costs – however, based on prior cost allocation information and assuming that the latest cost increases relate to the generation plant elements, the $240 million total would appear to include approximately $170 million for the generation plant, approximately $53 million for THELP transmission/ substation plant elements, and approximately $17 million for YEC/AEY System Upgrades. ~~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 will be~~is being~~ revised by THELP as required 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 has been committed~~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 $90~~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 and Canada has committed $100 million to the development phase (other funds are being provided during the planning phase). Any g~~G~~rant funding to be provided by British Columbia~~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 at an interest rate of 1%. YEC does not have further information at this time on other funding sources beyond government grants and CIB.

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 Amended 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 May~~rch~~ 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 8.5~~0~~ MW and not more than 8.75 MW."

QUESTION:

a) Please explain the significance of the upper limit of 8.75 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 Table~~s~~ A1~~and 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.

The revised Project design with its materially increased dispatchability raises less concern than the original design with regard to water availability assessments for dependable capacity as required during the Peak Winter Period. The 8.75 MW in the Amended EPA confirms understandings on the maximum delivered capacity to be provided at Jakes Corner as needed for the assessments required for the Buyer-AEY System Integration Study Report assessments.

ISSUE: **Operating rules**

REFERENCE: **Application, page 10, PDF page 13**

QUOTE: "Operating Rules for Seller's Plant (Schedule D of Amended EPA) - the Amended EPA requires Seller and Buyer to coordinate and schedule the delivery of Delivered Energy and Dependable Plant Capacity (each defined at the POI for delivery by Seller to Buyer) under the Operating Rules as set out in Schedule D attached to the Amended EPA. The Operating Rules include provisions that are focused on maximizing hydro storage and its effective use at YEC's direction to provide dependable capacity during the PWP and to displace thermal generation throughout the Winter Period ~~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)

SOP IPP contracts are take-or-pay arrangements; therefore, these IPP contracts are dispatched first in the generation stacking order, followed by YEC hydro and thermal assets. The revised Atlin hydro expansion project and Amended EPA, however, provide YEC with materially enhanced dispatchability – and therefore this project will be dispatched when feasible after the SOP IPP contracts, after YEC Whitehorse and Mayo

hydro assets, and before YEC Aishihik 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 prices determined based on expected ~~its~~ displacement of YEC's forecast thermal fuel generation costs at long-term average ("LTA") renewable sources for the YIS and the Project."

"3. Delivery of all Winter Energy available: while YEC will only pay for winter energy that is expected to displace~~s~~ 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 Amended EPA are based on $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. The b~~B~~enchmark 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 amended 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 34.00.8 GWh result in LTA thermal displacement of 24.18119.583 GWh (displacement at 71.263.5% 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 13.52.1 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, subject to the constraints and directions in the Operating Rules. 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 assumeds 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 section 4.3 "Operations"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 (Table~~s~~ A1 ~~and A2~~ of Submission) as well as the Amended 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 Amended 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 Amended 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 8.75 MW full

[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.

capacity has been planned throughout each day during each week pursuant to the Operating Rules:

a. Event #1: 1 hour when 8,7500~~00~~0 kWh Delivered Energy was expected to be provided; and
b. Event #2: 100 hours when 87500~~00~~,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: Reduction to 1MW for last 15 minutes of the hour, resulting in a reduction capability of 2,187.5 kWh = 15/60*8,750~~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 1 hour~~48 hours (2 days)~~, resulting is a reduction capability of 866,250~~416,000~~ kWh = ~~(800,000-99*48~~*8,750~~000)~~.

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 6,562.5~~8,000~~ kWh = (8,750~~000~~-2,187.5~~0~~)
   b. Event #2: Constraint Shortfall Energy equals ~~38~~48,7500~~0~~ kWh = (87500,000-866~~416~~,250~~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~~15,312.5~~,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: **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 modeled water year flows~~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 modeled water years~~records, while the low water year winter generation deliveries reflect the lowest hydro generation in water year 1978~~. (Although Winter Period includes period to May 31, the LTA energy delivery at34.0 GWh was modeled to May 15 to exclude energy from freshet.) The transmission losses between the Atlin generation location and delivery point at Jakes Corner is estimated to be at around 2.7%. Additional losses of 4.5% are added that reflect losses on the~~in~~ YIS system for estimated energy delivered from Jakes Corner to YEC's substation S150 at Whitehorse (these added losses take into account the material portion of the Delivered Energy expected to be used to supply customer loads on the southern Yukon AEY System ~~which is assumed at 6.2% based on losses approved for ATCO Electric Yukon in its most recent GRA (~~and assumes that AEY System Upgrades will result in continuation of past average losses on the AEY System 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?] *NTD: Original question no longer reflects the Submission.*

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)

Appendix A, Table A1 in the Amended Submission includes 51 modeled water years from 1970 to 2020. Therefore 1994-2014 is now included. ~~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 4.5~~6.2~~% losses assumed for AEY transmission reflect historical information, the required AEY System Upgrades, and Delivered Energy expected to be used for AEY customers on the southern Yukon AEY System. V~~, and v~~ariances are expected after AEY System Upgrades and addition of the Atlin deliveries. However, the AEY design for System Upgrades assume~~d~~ Atlin deliveries at the 8.75 MW maximum Atlin project delivery at Jakes Corner ~~10.575 MW (i.e., higher than the EPA allowed maximum of 8.5 MW)~~ and reflect~~ed~~ 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: **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." *NTD – This quote has been deleted from the Amended Submission.*

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):~~

~~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~~

~~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, the winter energy~~se~~ prices in the Amended EPA are in 2024$. One price is provided for 2024-2034 and another price for 2035 and the balance of the Amended EPA Term, based on LTA Delivered Energy. T~~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. T~~hese prices ~~all~~ escalate after 2024 at 50% of CPI and apply to all Delivered Energy and Monthly Constraint Energy during the Winter Period in each

Year,~~.~~ i.e., unlike the Original EPA, the Amended EPA does not provide for separate firm and non-firm energy prices during the Winter Period in each 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: **Water Storage Savings**

REFERENCE: **Application, Appendix A, Figure A21-1, page A-5, PDF page 40**

QUOTE:

QUESTION:

a) Figure A21-1 shows Water Storage Savings of 4.72.8 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 A21-1, total LTA thermal displacement of 24.219.6 GWh/year for the 2024 load is the total resulting from direct thermal displacement (19.56.7 GWh) and water storage savings thermal displacement (4.72.8 GWh).

As noted in Table A31-1, LTA thermal displacement has been estimated based on YECSIM model simulation runs for 38 water years. Key assumptions are noted in this table.

ISSUE: **Firm Winter Energy Price**

REFERENCE: **Application, Appendix B, footnote 165, page B-10, PDF page 54**

QUOTE: "Section 8.2 of the Amended 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, the~~se~~ winter energy prices in the Amended EPA are in 2024$. One price is provided for 2024-2034 and another price for 2035 and the balance of the Amended EPA Term, based on LTA Delivered Energy. ~~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 and apply to all Delivered Energy and Monthly Constraint Energy during the Winter Period in each Year, i.e., unlike the Original EPA, the Amended EPA does not provide for separate firm and non-firm energy prices during the Winter Period in each Year. ~~.~~

(c)

~~All p~~No pricing in the Amended EPA is ~~not~~ based on assumed low flow water years at Atlin. The Amended EPA winter energy pricing is based on~~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: **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 71.263.5% of all winter deliveries in these years)."

QUESTION:

a) Please explain how the 71.263.5% 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 71.263.5% equals the expected LTA thermal displacement from winter Amended EPA deliveries (24.18119.563 GWh at row 5) divided by LTA EPA deliveries (34.00.8 GWh at row 1). Similarly, for the years 2035 and the balance of the Amended EPA term, this percentage is adjusted to 50.948.7% (17.2895.003/34.00.8).

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 Amended Submission details Amended 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		
Winter Energy Price (Jan-May,Sept-Dec)	$0.135/kWh in 2024 plus 1/2 CPI after	$0.097/kWh in 2024 plus 1/2 CPI after
Dependable Plant Capacity Committed		
LCOC Reference Price	$200/kW-yr in Dec. 2023 plus CPI after	

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 Amended EPA (i.e., development and project costs risks are borne by THELP, and Amended 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 Amended EPA ~~firm and non-firm~~ energy prices have been set based on LTA thermal displacement benefits. Atlin Amended 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 Amended 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 Amended 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 $6.45.3 million/year until the end of 2034, and $5.04.5 million/year thereafter.[2]

- In contrast, SOP IPP deliveries for renewable projects with the same annual LTA energy delivery capability (41.536.2 GWh/year including summer period energy) and the same 2024$ YEC blended fuel cost of $0.19/kWh would cost YEC $7.96.88 million/yr. for energy only.

- Additional costs would also be needed with SOP IPP options in order to provide the equivalent 8.750 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 $1.756 million/year for 8.750 MW."

[2] The $6.45.3 million/year (2024$) until the end of 2034 (and the $5 million thereafter) assumes 8.750 MW dependable capacity ($1.756 million/year) plus 34.00.8 GWh/year winter delivered energy ($4.63.7 million/year for years until the end of 2034 and $3.3 million for years thereafter as per Appendix A, Table A3-2). The Project is capable of providing 7.55.4 GWh/year during summer, but no summer deliveries are assumed to be required from the Project given the forecast surplus of summer renewable energy. If 7.55.4 GWh of summer energy was required from the Project, and YEC's approved blended fuel cost (2024$) was $0.19/kWh, the added cost would be $0.75 million/year (price at 50% of the approved blended fuel cost).