



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)

1 **TOPIC: Deliveries above LTA**

2
3 **REFERENCE: YEC Application PDF page 14 of 136.**

4
5 **PREAMBLE: At Item 3 of PDF page 3, YEC states:**

6
7 **3. Delivery of all Winter Energy available: while YEC will**
8 **only pay for winter energy that displaces LTA forecast**
9 **thermal generation, YEC will take delivery each winter**
10 **season (Sep-May) of all available energy that the Project**
11 **is able to generate.**

12
13 **CW requires information to better understand pricing proposed in**
14 **the agreement.**

15
16 **QUESTION:**

17
18 a) Please fully explain how the volumes above the LTA will be priced. In the response
19 please fully explain why the price for surplus energy should not be priced at the
20 YEC cost of hydro energy.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Winter delivery volumes in any Year, whether above or below the LTA, will all have the
27 same Winter Energy Price (see Table 3-1 in YEC's Submission).

28
29 Please see responses to YUB-YEC-1-11, YUB-YEC-1-12 and YUB-YEC-1-24 for
30 explanations as to how EPA energy prices were determined based on displaced thermal
31 fuel generation costs.

32
33 In developing energy prices for IPP purchases (including purchases under the Atlin EPA)
34 no estimates have been developed of YEC cost savings for reduced non-fuel O&M costs
35 for thermal or hydro generation, i.e., the focus has remained on thermal generation fuel
36 cost savings. EPA deliveries will result in some added YEC cost savings for displaced
37 thermal generation non-fuel O&M and (to a smaller degree) for displaced hydro generation
38 due to increased spills at YIS hydro facilities.

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

2
3 **REFERENCE: YEC Application, PDF page 67 of 136.**

4
5 **PREAMBLE: Section 2.1 (d) sets out the Conditions Precedent. The Condition**
6 **Dates for the first two of these have passed. CW would like a**
7 **status update.**
8

9 **QUESTION:**

10
11 a) Has the Condition Precedent in Section 2.1 (d) (i) been met? If yes, please provide
12 a copy of the referenced Interconnection Agreement. If no, please explain the
13 status and any impact flowing from the failure to meet this Condition Precedent by
14 the Condition Date
15

16 b) Has the Condition Precedent in Section 2.1 (d) (ii) been met? If no, please explain
17 the status and any impact flowing from the failure to meet this Condition Precedent
18 by the Condition Date.
19

20 **ANSWER:**

21
22 **(a) and (b)**

23
24 YEC and THELP have agreed to extend the dates for the satisfaction of the following
25 conditions precedent in the EPA:
26

- 27 • 2.1 (d)(i) and (ix) extended from January 31, 2022 to May 31, 2022;
28 • 2.1(d)(ii) extended from February 15, 2022 to May 31, 2022
29 • 2.1(d)(vii) extended from February 28, 2022 to May 31, 2022.
30

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

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

Nathaniel YEE
(NY)

1 **REFERENCE:** The FAQ on the THELP web page for the Project notes that “The
2 Atlin Hydro Expansion Project will only generate power for the
3 Yukon once the power needs of Atlin have been met. The power
4 needs of Atlin are the first priority when it comes to the water
5 resources of Surprise Lake.”
6

7 **QUESTION:**
8

9 a) Is this consistent with YEC’s understanding of the agreement? If not, please
10 provide specifics.
11

12 **ANSWER:**
13

14 **(a)**
15

16 YEC’s understanding on this matter is as follows:
17

- 18 1. The Atlin Hydro Expansion Project is a separate facility from the Existing Plant,
19 with all Energy from the Project to be exclusively provided only to YEC as provided
20 in Section 7.1 of the EPA.
21
- 22 2. The expected water availability from Surprise Lake is sufficient to meet expected
23 power needs of Atlin (as supplied from the Existing Plant) as well as provide 8.5 to
24 8.75 MW of dependable capacity to YEC during the Peak Winter Period (see
25 Appendix A to the Submission, Table A1).
26
- 27 3. THELP will cause Xeiti Limited Partnership (“XLP”), by its general partner Atlin
28 Power Limited (“APL”), to not amend, modify, or make any changes to the Existing
29 Plant which would have a material adverse effect on Seller’s ability to deliver and
30 Buyer’s ability to receive during each Peak Winter Period the minimum energy
31 deliveries as set out in Sections 7.2(a) and 7.3 of the EPA.
32
- 33 4. The EPA does not have any specific provision stating that the Atlin Hydro
34 Expansion Project will only generate power for the Yukon once the power needs
35 of Atlin have been met.

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

1 **TOPIC:**

2
3 **REFERENCE:** In the public presentation on 11-Feb, the slide listing capacities
4 had in very large print "Eliminates 4 Rental Diesel Engines Each
5 Winter."
6

7 **PREAMBLE:**

8
9 **QUESTION:**

10
11 a) When the Project comes online, does YEC actually expect to have four fewer
12 rentals than are currently installed, or was this just implied to sell the Project?
13

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

20 **ANSWER:**

21
22 **(a) and (b)**

23
24 Please see response to YUB-YEC-1-13(c) for available forecasts of diesel rental
25 requirements with and without the Project, focusing on winter 2024/25 and 2030/31. This
26 information indicates that the EPA prior to in-service of Moon Lake Pumped Storage will
27 reduce diesel rentals by 5 units (assuming each unit capacity = 1.8 MW).
28

29 **REVISED RESPONSE**

30
31 On March 16, 2022 Mr. Yee filed Notice of Motion regarding YEC's response to b) part of
32 this IR. Mr. Yee specifically notes that YEC did not provide the number of diesel rentals
33 for each season for 2022-2035 as requested in the question.
34

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

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

3
4 Table 4-1 of the Amended Application provides forecast non-industrial peak, dependable
5 capacity and capacity shortfall under N-1 for the period from 2021/22 through 2030/31 and
6 Figure 4-1 of the Application illustrates similar information that extends to 2041/42 years.
7 The information from Table 4-1 and Figure 4-1 is used to populate the table below to
8 provide information as requested by Mr. Lee in his Motion for further information, however,
9 the table excludes the years 2017/18 through 2020/21 as the table and figure in the
10 Amended Application did not include those years as they are not relevant and not useful
11 to this review process; in addition, information for these years was not included in the
12 original information request.

13
14 The number of spares will depend on total number of rental units, the number of locations,
15 and potentially other considerations relating to requirements and costs. Therefore,
16 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 Upgrade, 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

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 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)**

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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 3 Figure 2-1**

6
7 **QUESTION:**

8
9 a) Please provide a digital higher resolution version of Figure 2-1 so that all the project
10 components can be clearly seen.

11
12 b) Will the new Atlin Project have a different penstock than the existing plant, and if
13 so, will they come from the same head pond?

14
15 **ANSWER:**

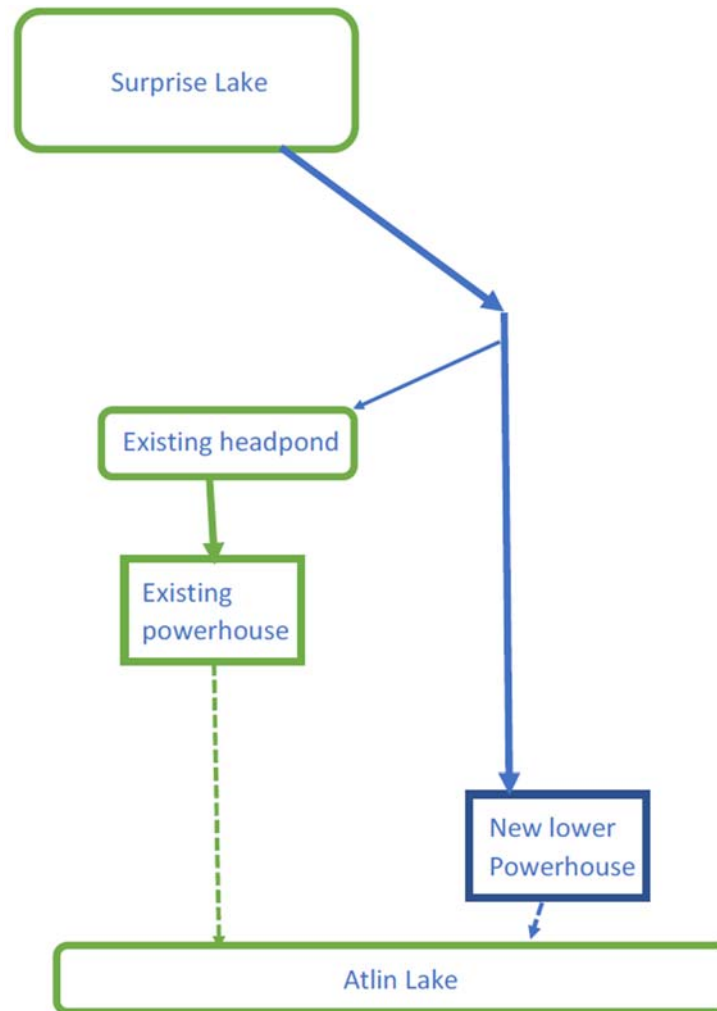
16
17 **(a)**

18
19 Appendix 1 provides an expanded Figure 2-1 so that all project components can be clearly
20 seen.

21
22 **(b)**

23
24 The Atlin Project will have a new Penstock from Surprise Lake to the Powerhouse. The
25 Existing Plant is also planned to have a tap from the same new Penstock that originates
26 at Surprise Lake. The beginning of the new Penstock at Surprise Lake is shown in Figure
27 2-1 attached (the Penstock is the larger solid blue line between Surprise Lake and the
28 new lower Powerhouse). The tap from the new Penstock to the Existing Plant is also shown
29 on Figure 2-1 attached (the tap is the smaller solid blue line between the Penstock and
30 the existing headpond that then connects to the existing powerhouse).

Appendix 1 - Expanded Figure 2-1



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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 4 Footnote 7:**

6
7 **QUESTION:**

8
9 a) Is a minus 38°C day defined in a manner consistent with the answer to JM-YEC-
10 1-3?

11
12 b) Why is the Yukon Energy (YEC) non-industrial peak load relevant?

13
14 c) If it is relevant, is it relevant for the N-1 capacity requirement criterion for the non-
15 industrial peak load only?

16
17 d) Are the total peak load and energy requirements with industrial customers not
18 much more relevant for the thermal energy displacements that are calculated in
19 YEC's submission and on which the purchase price for energy is based? Please
20 explain in detail.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Yes, it is the average daily temperature drop below -38°C.

27
28 **(b) and (c)**

29
30 Non-industrial peak load is the relevant load for the single contingency dependable
31 capacity requirement criterion (see below). This criterion has been used to assess the
32 required dependable capacity from the Atlin Project.

33
34 Yukon Energy's generation capacity planning criterion for the YIS is based on the single
35 contingency (N-1) dependable capacity criterion, under which the YIS is required to have
36 enough dependable capacity to supply the forecast non-industrial peak winter demand
37 under the largest single contingency. This criterion considers the ability to interrupt large

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

4
5 There is also a direct correlation between non-industrial peak and prolonged cold weather
6 as non-industrial peak is primarily driven by residential demand for services such as space
7 heating along with other residential uses. Yukon's electricity demand typically peaks
8 during or shortly after prolonged periods of cold winter days. YEC experienced a record
9 peak in January 2020 when over nine days the average daily temperature remained below
10 -30°C [please see response to JM-YEC-1-3].

11
12 **(d)**

13
14 The peak demand non-industrial load is only considered for the dependable capacity
15 requirement and EPA benefits from displacement of new thermal generation capacity
16 (permanent new units or rental diesel units). All firm load (including industrial) is
17 considered for assessing EPA energy benefits in displacing thermal generation.

18
19 There are two benefits from the EPA for the YIS:

- 20
21 • The Project provides dependable capacity otherwise expected to be required by
22 using new thermal generation capacity (permanent new units or diesel rentals).
23
24 • The Project displaces thermal generation energy.
25

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

- 28
29 • **Dependable Capacity Payment:** YEC pays THELP the Dependable Capacity
30 Payment for each PWP based on the Dependable Plant Capacity Committed
31 [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].

- 1 2024]. The requirement for this dependable capacity is driven by N-1 capacity
2 criterion which is based on non-industrial peak as reviewed in response to the
3 previous question in this IR.
4
5 • **Winter Energy Delivery:** YEC pays THELP for delivered energy based on Winter
6 Energy Price of \$0.135/kWh for 2024-2034 and \$0.097/kWh for 2035 and
7 thereafter, all in 2024\$ and increased by 50% of CPI for each year. These Winter
8 Energy Prices are determined based on total YEC load, including industrial load
9 as reviewed in Table A3 in Appendix A [i.e., LTA thermal energy displacements
10 are determined including industrial load].

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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 5 top: "Expected Winter Period deliveries to YEC per**
6 **calendar year are 34.0 GWh LTA energy and 23.4 GWh firm energy**
7 **during the lowest water year."**

8
9 **And: YEC 2021 GRA Table 2.2 on page 2-17 which shows on line**
10 **27 long term average (LTA) forecast thermal generation at 15.6%**
11 **(84,306/538,726) and actual thermal generation on line 21 plus line**
12 **22 at 5.6%.**

13
14 **QUESTION:**

15
16 a) Has YEC calculated the correlations of the Atlin Surprise Lake water years with
17 each of the following and if so, please provide the results, and if not please explain
18 why not.

- 19 i. Whitehorse hydro
20 ii. Aishihik hydro
21 iii. Mayo hydro, and
22 iv. The YIS hydro as a whole (excluding Fish Lake).

23
24 b) Please discuss what a correlation or a lack of correlation between the Atlin project
25 and any or all of the YEC hydro plants would mean for thermal energy
26 displacement.

27
28 c) If YEC has not used correlations, please explain how YEC has ensured that its
29 thermal energy displacement calculations were as accurate as possible.

30
31 d) Does YEC still use weekly time step modelling for potential new projects such as
32 this one

33
34 e) In the YEC 2017-2018 GRA, IR JM-YEC-2-6 and in the transcript at pages 211-
35 212, hourly time step modelling was discussed. Does YEC now have an hourly
36 time step model, and if so, was it used in calculating thermal displacements at
37 times when thermal generation is only used for portions of the day? And if not how
38 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)?

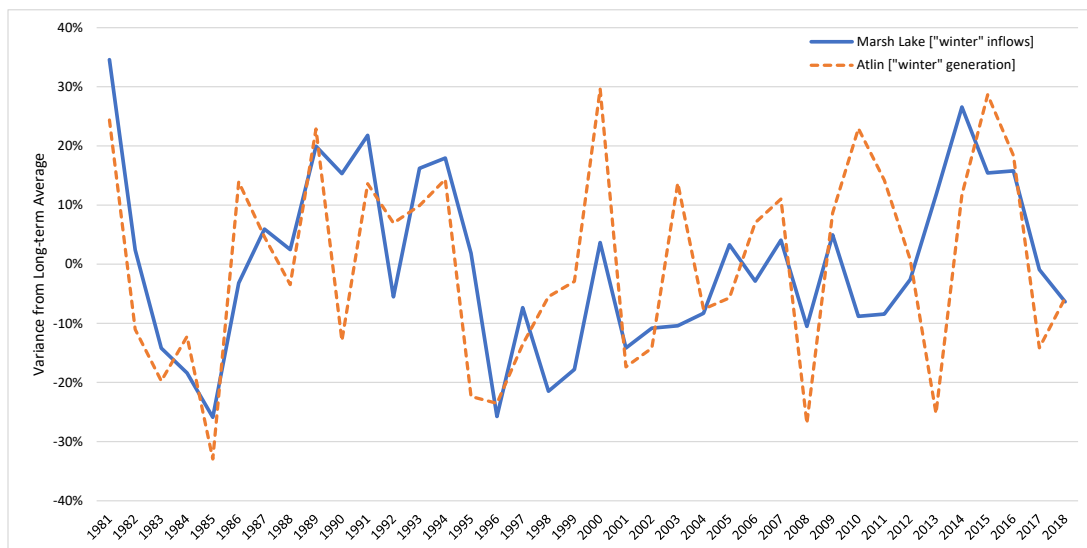
ANSWER:

(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 1981-2018 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 1970-2020 water years. YEC LTA hydro generation estimates are based on 1981-2018 water years. Therefore, the figure uses 1981-2018 years 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 mutates 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].
- The EPA energy pricings were determined based on LTA Atlin energy deliveries.
- 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).

1 (e)

2
3 The LTA thermal displacement benefits of the Atlin project estimated using the YECSIM
4 model reflect seasonality of the intermittent resources such as wind and solar IPPs. The
5 weekly load shapes were developed for each IPP resource which affects the LTA thermal
6 requirements.

7
8 YEC does not expect that the daily/hourly variations of the IPPs will have significant impact
9 to the thermal displacement benefits considering:

- 10
- 11 • The impacts, if any, of the daily/hourly variances affect the LTA thermal generation
12 under both with and without Atlin project [i.e., the delta is not impacted
13 significantly].
 - 14
 - 15 • A long-term average over 38 water years has been used for the calculations of
16 LTA thermal displacement benefits reducing the impact, if any, of the daily/hourly
17 variances.

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

2
3 **REFERENCE:**

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

6
7 **QUESTION:**

8
9 a) For the YIS Please provide a table of monthly actual hydro generation, actual other
10 renewable energy generation (microgeneration, IPP SOP, etc.), actual thermal
11 generation, and actual total generation excluding any secondary sales; plus
12 additional columns (or rows) for actual secondary sales generation and “spilled”
13 surplus (potential) generation for each the years 2017 to 2021 inclusive. The
14 months may be placed in rows and the generation sources in columns or vice versa
15 as is most convenient for YEC.

16
17 b) Please provide similar tables for the YIS for the years 2024 and 2035 as forecast
18 and assumed in preparing this EPA.

19
20 **ANSWER:**

21
22 **(a) and (b)**

23
24 Please see Table 1 for actual generation by source for 2017-2021 and Table 2 for the
25 forecast generation used for Atlin EPA thermal displacement analysis.

26
27 Please note that YEC does not administer the microgeneration program and therefore
28 does not have the actual generation numbers. The microgeneration totals are embedded
29 in actual generation numbers [i.e., the actual generation numbers reflect reduced load due
30 to microgeneration load generated by customers].

31
32 The forecast incremental microgeneration numbers are provided to YEC by the
33 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).

1 **REVISED RESPONSE**

2
3 **(a) and (b)**

4
5 On March 14, 2022, Mr. Maissan by email correspondence to the Board requested further
6 information regarding this response noting that the response did not include a column of
7 figures (estimates) for the summer surplus generation and “without some hard figures as
8 to what the actual surplus is or will be one cannot get a good overall picture of the YIS and
9 its winter - summer energy imbalance.” Mr. Maissan requested that YEC provide this
10 further information.
11

12 Please see updated Table 1 and 2 below. For the purposes of this analysis, summer
13 months are May through October which differs from Summer Period as defined in the EPA
14 (June through August).
15

16 With respect to the source of summer surplus estimates, Table 1 figures were developed
17 based on summer month spill records excluding actual secondary sales.¹ These years
18 showed considerable variability in water conditions. Overall, 2017 and 2020 were higher
19 water years for Aishihik, and 2021 was a higher water year for Whitehorse. Therefore,
20 Table 1 shows higher summer surplus energy volume for those years. Lower water
21 availability in 2018 and 2019 accounts for lower summer surplus energy volume for those
22 years.
23

24 Table 2 on forecast conditions for 2024 and 2035 – energy generation is forecast based
25 on LTA water and other renewable resource availability, with no forecast secondary sales.
26 The increases in summer surplus energy volumes for 2024 and 2035 load cases are
27 predominantly due to added renewable energy options, including IPPs, which lead to
28 increased spills of YEC hydro generation capability. JM-YEC-1-12(a) provides a figure
29 showing estimated summer surplus energy for 2030.
30
31
32
33
34
35

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	39.08	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 in the Submission for annual summaries. Atlin LTA winter deliveries to Jakes Corner are 34.0 GWh (row 1 in Table A3-1); Atlin deliveries for LTA thermal displacement assessments with YECSIM assume 4.5% 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**

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 6: "Project capital costs have been estimated to date at**
6 **approximately \$206 million."**

7
8 **QUESTION:**

9
10 a) If YEC were to complete a project identical in all respects to the Atlin Project,
11 including a 40-year life, for \$240 million without any grant funding what would be
12 the levelized cost of energy (LCOE) for all energy produced, and for the energy
13 that is forecast to displace thermal generation only.

14
15 b) What would be the levelized cost of capacity (LCOC)?

16
17 c) Please repeat the calculations provided in (a) and (b) above for a project with a net
18 capital cost of \$90 million.

19
20 **ANSWER:**

21
22 **(a) through (c)**

23
24 Please see the table in Appendix A. The analysis assumes the Project is located at Atlin
25 with same energy deliveries at Jakes Corner.

Appendix A

	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 million [2024\$].
2. Grant amount assumed at \$150 million [2024\$].
3. Fixed O&M at \$2.0 million/year [2024\$] – reflects approximately 0.8% of hydro generation plant \$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 GWh and LTA thermal displacement benefits at 24.2 GWh.
7. Weighted Average Cost of Capital at 4.59% (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 41.5 GWh of energy annually on a long-term basis, only 24.2 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 24.2 GWh is based on assumptions noted in Table A3 in Appendix A of the Submission, and will change depending on the load and other renewable resources on the YIS. For

- 1 example, the lower load forecast for 2035 as per Table A3 of the Submission shows lower
- 2 LTA thermal displacement benefits at 17.3 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.

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

3
4 **(b)**
5

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

- 8 i. Jake's Corner (JC) towards Teslin: 2.452 MW at JC side
9 Jake's Corner towards Whitehorse: ~6.25 MW [~6 MW] with only 2.06 MW
10 [1.90 MW] delivered at Whitehorse S150 substation (several loads along
11 S150–Jake Corner's path + line losses).
12
13 ii. North M'Clintock road is fed from a single phase 14.4kV distribution out of
14 the South M'Clintock Substation, 500kVA, 34.5kV – 14.4kV. This
15 substation is single phase and not a significant load, it feeds Army Beach,
16 M'Clintock River Road and North M'Clintock/Swan Haven. It is modelled
17 as part of the load at Carcross Cut-off. See question "b" sub-question "iii"
18
19 iii. 4.78 MW out of Carcross Cut-off towards MacRae.
20 2.10 MW [1.945 MW] through MacRae towards Whitehorse S150
21
22 iv. From Jake's Corner: 2.06 MW [1.90 MW]
23 From P126 Whitehorse Diesel: 4.98 MW
24 From S171 Riverside (through Whitehorse S150 138 kV): 24.49 MW
25 From Whitehorse P125: 11.6 MW

1 TOPIC: Section 3 Overview of the Electricity Purchase Agreement

2
3 REFERENCE:

4
5 PREAMBLE: Page 11 near top: “Delivery of all Winter Energy available: while
6 YEC will only pay for winter energy that displaces thermal
7 generation, YEC will take delivery each winter season (Sept-May)
8 of all available energy that the Project is able to generate.” and

9
10 Page 12 “Delivered Energy”, and

11
12 Page 14 Table 3.1

13
14 QUESTION:

- 15
16 a) The page 11 reference states that YEC will only pay for winter energy that
17 displaces thermal generation but the page 12 reference and the pricing in Table 3-
18 1 implies that non-firm winter energy (all available energy?) is paid for but at
19 reduces rates. Please clarify this apparent discrepancy.

20
21 ANSWER:

22
23 (a)

24
25 The principle #2 at page 11 is that the EPA price is based on YEC only paying for forecast
26 thermal generation displaced by winter energy (e.g., LTA displacement of 24.2 GWh for
27 2024). Principle #3 then states that YEC purchases all available winter energy that THELP
28 provides (LTA deliveries of 34.0 GWh).

29
30 The two principles are reconciled by setting the energy price appropriately.

- 31
32 • LTA displacement in 2024 equals only approximately 71.2% of LTA deliveries.
33
34 • The average energy price paid of all energy delivered is then set at 71.2% of the
35 thermal blend fuel price, i.e., YEC’s payment is based on only paying for forecast
36 thermal generation displaced.

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

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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 11 “Reliance of forecasts and forecast risk”**

6
7 **QUESTION:**

- 8
9 a) This section appears a bit confusing. Please provide a table of energy costs by
10 year for each of the 40 years of the Electricity Purchase Agreement (EPA) starting
11 in 2024 and finishing in 2065 with YEC forecast loads as in the EPA. Assume no
12 summer energy purchase, no carbon tax, and LTA water availability in each year,
13 i.e. 34.0 GWh per winter energy purchase. Assume an inflation rate and CPI of 2%
14 per year including on the YUB Price of \$0.19 per kWh. Please show each cost
15 component (as per Table 3-1 on page 14) separately and the total cost.
16
17 b) Please provide a similar table for the 40 years with the mining load continuing to
18 2044. Assume the same non-industrial load growth as in (a) above.
19
20 c) Please provide a similar table for the 40 years with the mining load terminating in
21 2029. Assume the same non-industrial load growth as in (a) above.
22
23 d) For each of (a) to (c) can an LCOE using the total cost be calculated? If so, please
24 provide these calculations.
25

26 **ANSWER:**

27
28 **(a) and (c)**

29
30 Please see the table below for the requested information. Please also see response to
31 JM-YEC-1-16. For simplicity, full LTA deliveries assumed each calendar year
32 (commissioning in October is ignored) and capacity payments are recorded fully for each
33 calendar year.
34

35 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 [$\$0.19 \times \text{inflation} = \$0.428 \times 12.9\% \times 14.2 / 33.95$]. This rate is applied to energy delivered (34.0 GWh assumed each year).

	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

Yukon Utilities Board
Review of an Electricity Purchase Agreement
between YEC and THELP

Yukon Energy Corporation
JM-YEC-1-10 REVISED AMENDED

	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	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

Yukon Utilities Board
Review of an Electricity Purchase Agreement
between YEC and THELP

Yukon Energy Corporation
JM-YEC-1-10 REVISED AMENDED

1

	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

2

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	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

5

6

7

8 In the above examples the added winter load remains below the max 68 GWh. As
9 illustrated in the example provided in response to JM-YEC-1-16, the added winter load for
10 EPA purposes is capped at 68 GWh, therefore, if the added winter load is higher than 68
11 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 prudence 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	\$134.23	\$140.53
LCOE based on EPA Payments (\$/kWh), 2024\$	\$0.166	\$0.174

¹ Assumed at 2.54%, based on nominal WACC of 4.59% (2021 GRA Compliance Filing) and assumed inflation of 2%/year

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

4
5 In the original response YEC had noted that the EPA energy pricing is not based on LCOE,
6 but based on LTA thermal displacement benefits [i.e., YEC does not pay the energy rate
7 based on Project LCOE]. The EPA energy pricing approach directly addresses prudence
8 of this pricing by linking it to estimated LTA thermal fuel costs saved and estimated thermal
9 dependable capacity costs saved [based on a levelized cost of capital calculation].

10
11 Levelized cost assessments normally are based on a project's total capital and O&M costs
12 and its total annual energy generation capability (i.e., all months) over its life. EPA pricing
13 for the Atlin Hydro Expansion Project, however, is not based on THELP costs for the
14 project, using instead estimated costs of displaced LTA thermal fuel applied against
15 project energy deliveries during only the defined winter period as well as dependable
16 capacity payments based on dependable capacity to be provided by the Project.

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

	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
	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	8.885
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	

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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page 23 second bullet**

6
7 **QUESTION:**

8
9 a) Please provide the electrical energy forecast that indicated relatively stable non-
10 industrial loads for the last 30-year period of the EPA from 2034 to 2065. What is
11 the annual non-industrial electrical energy load growth rate through the 40-year
12 EPA and through the last 30 years in particular?

13
14 b) Yukon has been experiencing significant population growth, experiencing the
15 increasing use of electric heat for residential dwellings including switching to
16 electric heat from fossil fuels, and Yukoners are being encouraged to switch to
17 electric vehicles. Using only a low growth forecast and not considering the
18 possibility of higher growth rates due to these factors appears imprudent when
19 considering long-term ratepayer impacts. Please explain.

20
21 c) Please prepare an analysis using an annual electrical energy growth rate of 1.5%
22 per year for this 30-year period from 2035 to 2065 inclusive and assume that the
23 YUB Price will increase at 2% per year from \$0.19 per kWh in 2024 in order to
24 show what the ratepayer impact will be compared to assumptions in this
25 submission. As part of the analysis please prepare a table of 40 years of energy
26 costs such as those provided in answer to JM-YEC-1-10 for comparison purposes.

27
28 **ANSWER:**

29
30 **(a)**

31
32 The referenced quote is addressing forecast energy load on the YIS that will determine
33 opportunities for thermal energy displacement benefits due to the EPA.

34
35 YEC's available long-term forecasts are those provided in the 10-Year Renewable
36 Electricity Plan (see YUB-YEC-1-32, Attachment 1; summarized in Submission, Figure 4-
37 1 and Table 4-1).

1 YEC's available forecasts show only non-industrial load after 2034, and also show non-
2 industrial load being expected to stop material growth by about 2030, becoming relatively
3 stable at about 0.5% per year after including provision for new EV load growth¹. The
4 available forecasts showing this expected non-industrial load do not extend beyond about
5 2041.

6
7 **(b)**

8
9 The Atlin EPA energy price is based on the benefits forecast from displaced thermal
10 generation. This EPA price is reduced after 2034 to reflect forecast YIS loads without
11 industrial customers. For the purpose of setting this EPA price, which locks in ratepayer
12 costs for the EPA after 2034, it is prudent and reasonable to utilize these available
13 forecasts. The rate impact risk for ratepayers is that actual loads will be less than forecast,
14 resulting in the EPA price being higher than the actual displaced thermal benefits.
15 Ratepayers will benefit if actual loads are higher than this forecast after 2034 – and THELP
16 will share in these benefits through the Additional Payment provisions of the EPA.

17
18 **(c)**

19
20 Please see Table 1 for requested information which assumes 1.5%/year growth for non-
21 industrial winter load after 2035 (EPA assumed 388 GWh 2035 non-industrial winter load)
22 and the CPI at 2% for energy and capacity rate calculations as well as the YUB price at
23 \$0.19/kWh [2024\$] also with inflation at 2%/year. Please note that the added winter load
24 for the EPA purposes is capped at 68 GWh, therefore, the years 2046 and thereafter only
25 show added winter load at 68 GWh for the purpose of the Additional Payment forecast.

26
27 Table 1 shows the impact on the EPA payments – it does not show the impact on overall
28 ratepayer costs from the changed assumptions. Assessments of overall ratepayer costs
29 would require addressing forecast new resources to deal with the added load, and the mix
30 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	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

Yukon Utilities Board
Review of an Electricity Purchase Agreement
between YEC and THELP

Yukon Energy Corporation
JM-YEC-1-16 AMENDED

	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
1 Total Payment, \$million	9.381	9.528	9.677	9.829	9.983	10.140	10.300	10.462	10.628	10.796
2										
	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
3 Total Payment, \$million	10.967	11.141	11.318	11.498	11.681	11.868	12.058	12.251	12.447	12.647

1 **TOPIC:** **Attachment A Electricity Purchase Agreement**

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

11

12 **ANSWER:**

13

14 **(a)**

15

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

1 **TOPIC:** **Attachment A Electricity Purchase Agreement**

2

3 **REFERENCE:**

4

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

7

8 **QUESTION:**

9

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

12

13 **ANSWER:**

14

15 **(a)**

16

17 The wording in section 6.5 has been corrected in the Amended EPA as shown in the
18 revised PREAMBLE quote above.

1 **TOPIC: Attachment A Electricity Purchase Agreement**

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page A1-20 clause 8.3 (a) (iii) "Capacity Shortfalls"**

6
7 **QUESTION:**

8
9 a) This clause appears to say that Seller will be paid for a minimum of 50% of the
10 Actual Dependable Plant Capacity Committed in a particular year, is this the
11 correct interpretation? If not please clarify.

12
13 b) Is the Actual Dependable Plant Capacity Committed 8.5 MW to 8.75 MW or can it
14 be different? Please explain.

15
16 **ANSWER:**

17
18 **(a)**

19
20 Yes, the clause caps the Capacity Shortfall in any Peak Winter Period at 50% of Actual
21 Dependable Plant Capacity Committed, which in turn depends on the annual Dependable
22 Plant Capacity Test.

23
24 **(b)**

25
26 Actual Dependable Plant Capacity Committed can be different than being between 8.5
27 and 8.75 MW, and could be as low as zero under some circumstances.

28
29 Actual Dependable Plant Capacity Committed is in effect the capacity that was paid for
30 during a Peak Winter Period (PWP). It is limited for each PWP by the Dependable Plant
31 Capacity Committed or DPCC, as used to determine Dependable Capacity Payments that
32 were made for the PWP. Dependable Plant Capacity Committed is:

- 33
34 1. Dependable Plant Capacity in kW up to a maximum of 8,750 kW that is confirmed
35 at the final commercial operation date [COD] for Seller's Plant [therefore, the 8.75
36 MW is a cap, but this result during COD could be less than the 8.5 MW minimum
37 required at COD], less

- 1 2. The reduction for a PWP as provided for in a Dependable Plant Capacity Test
- 2 under Section 5.5 or Notice under Section 6.2 [these reductions could in principle
- 3 reduce the DPCC to well below 8.5 MW, including to zero].

1 **TOPIC:** **Attachment A Electricity Purchase Agreement**

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

11

12 **ANSWER:**

13

14 **(a)**

15

16 This has been corrected in the Amended EPA.

1 **TOPIC:** **Attachment A Electricity Purchase Agreement**

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

10

11 **ANSWER:**

12

13 **(a)**

14

15 Section 9.1 has been corrected in the Amended EPA.

1 **TOPIC:** **Attachment A Electricity Purchase Agreement**

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

11

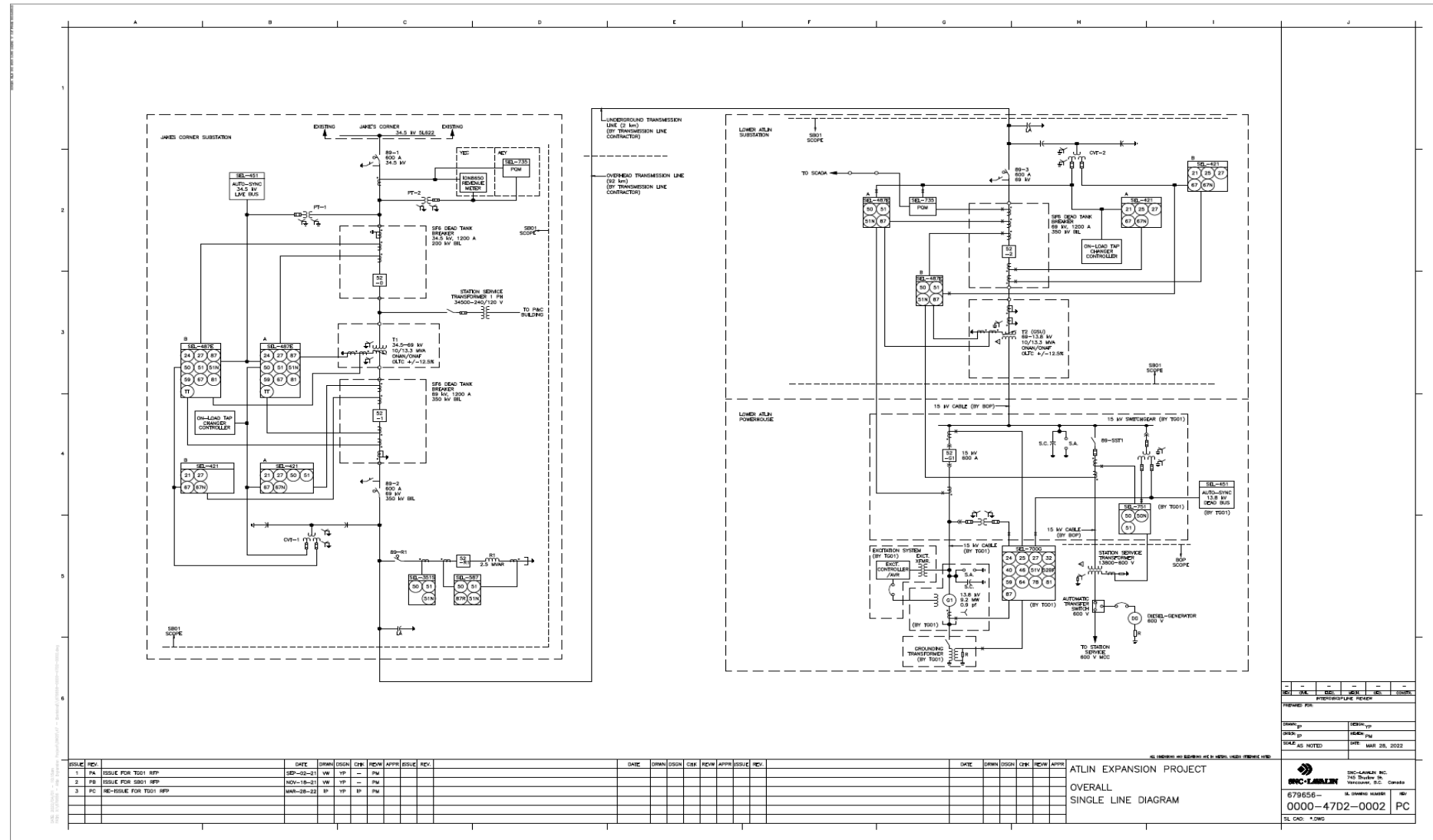
12 **ANSWER:**

13

14 **(a)**

15

16 Please see page 2 to this response.



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 Winter Energy Price for all 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.

1 **(b)**

2
3 The EPA summer energy price is not designed to support secondary (interruptible) sales.

4
5 The EPA provides that YEC will only receive summer delivered energy when YEC
6 specifically requests such energy and YEC would not make this request unless it was
7 required to displace thermal generation during this period. In this specific situation where
8 thermal generation is required on the system, YEC would not offer secondary sales as
9 prescribed by the secondary sales rate schedule rules.

10
11 **(c)**

12
13 The \$200/kW-yr (2024\$) dependable capacity price covers the per kW capital and non-
14 fuel O&M levelized costs for a new diesel plant (see response to YUB-YEC-1-13(a) for
15 more detailed review). There are no deductions for any grant funds provided to THELP,
16 as YEC would not expect that grant funding would be available for YEC to develop a new
17 greenfield diesel plant.

18
19 **(d)**

20
21 The exact routing of funding has not been agreed; it is possible that YDC could be involved
22 in the transfer of funds from YG to THELP. YEC will not be contributing funding directly
23 for the Atlin project.

1 **TOPIC:**

2
3 **REFERENCE:** Proposed Atlin Hydro Expansion Project Page 26 Footnote 41

4
5 ⁴¹ The \$6.4 million/year (2024\$) until the end of 2034 (and the \$5
6 million thereafter) assumes 8.75 MW dependable capacity (\$1.75
7 million/year) plus 34.0 GWh/year winter delivered energy (\$4.6
8 million/year for the years to the end of 2034 and \$3.3 million for
9 the years thereafter as per Appendix A, Table A3). The Project is
10 capable of providing 7.8 GWh/year during summer, but no
11 summer deliveries are assumed to be required from the Project
12 given the forecast surplus of summer renewable energy. If 7.8
13 GWh of summer energy was required from the Project, and YEC's
14 approved blended fuel cost (2024\$) was \$0.19/kWh, the added cost
15 would be \$0.7 million/year (price at 50% of the approved blended
16 fuel cost).

17
18 **PREAMBLE:**

19
20 **QUESTION:**

- 21
22 a) Is this \$6.4 million per year total cost (\$1.75 million dependable capacity plus \$4.6
23 million delivered energy), all the proposed costs that will be passed on to
24 ratepayers? If not, explain.
25
26 b) Please discuss the pros and [sic] cons of summer deliverable energy for secondary
27 usage.
28
29 c) Would the current approved secondary charge be sufficient to cover the proposed
30 summer rate of 50% of the approved fuel cost plus YEC management costs?
31 Please elaborate.

32
33 **ANSWER:**

34
35 **(a)**
36

1 The referenced costs are the total costs for energy delivered during the winter period when
2 there is no carbon charge applicable to ratepayers, no Monthly Constraint Energy, and
3 (after 2034) no Added Load. This cost is stated in 2024\$ and is subject CPI increases as
4 noted in the EPA and Table 3-1 of the Submission. Negotiation and YUB proceeding costs
5 for the EPA to be recovered from ratepayers are not included in the referenced costs.

6

7 **(b) and (c)**

8

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

**Yukon Utilities Board
(YUB)**

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

2
3 **REFERENCE:** **May 18, 2021 Minister McPhee's letter - Referral of the Electricity**
4 **Purchase Agreement with Tlingit Homeland Energy LP**

5
6 **QUOTE:** "3. The YUB shall report on, and make recommendations about, the
7 necessity for the Agreement, its timing, and proposed terms and
8 conditions, with particular regard to:

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

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

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

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

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

25 f. Whether it is prudent to enter into the Agreement as proposed at
26 this time."
27

28 **QUESTION:**

29
30 a) Please provide a summary of how YEC's application meets each item in the
31 enumerated list from the Minister (and in terms of need, timing and with reference
32 to the terms and conditions in the agreement).

33
34 b) How do the terms of the agreement, and specifically the conditions precedent in
35 the agreement, affect the Board's review of factors (a) to (f) above?

1 **ANSWER:**

2
3 **(a) and (b)**

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

- 7
8 1. Item 3(a) of the Minister's list is addressed in section 4.1 of the Submission, which
9 also includes:
10 a. Section 4.1.1 which addresses item 3(c) of the Minister's list: and
11 b. Section 4.1.2 which addresses item 3 (e) of the Minister's list.
12 2. Item 3(b) of the Minister's list is addressed in Section 4.2 of the Submission.
13 3. Item 3(d) of the Minister's list is addressed in Section 4.3 of the Submission.
14 4. Item 3(f) of the Minister's list is addressed in Section 4.4 of the Submission.¹

15
16 In summary, Section 4 of the Submission documents the need for the EPA and its
17 prudence under reasonable electric load forecasts.

- 18
19 • The EPA provides 8.75 MW of renewable dependable capacity during the Peak
20 Winter Period (displacing the equivalent of four rented diesels) as well as LTA
21 annual Winter Period renewable energy of 34.0 GWh that is expected to displace
22 between 17.3 and 24.2 GWh/year of LTA thermal generation over the 40 year EPA
23 term.
24
25 • The EPA enables the only near-term resource option other than the BESS to
26 provide material added renewable dependable capacity benefits.
27
28 • The EPA provides for all required YEC/AEY study and asset development costs
29 (e.g., for required System Upgrades) to be fully funded in advance by THELP at
30 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.

- 1 • The EPA impacts on ongoing YEC costs and customer rates are tied to actual
2 THELP deliveries of energy and dependable capacity, and mirror or improve on
3 what would be expected to occur with the least cost permanent thermal resource
4 option. The EPA effect on customer rates is materially lower than the option of
5 equivalent renewable SOP IPP renewable supplies.
6
- 7 • The EPA is expected to maintain, and likely to enhance, current service reliability.
8
- 9 • The EPA places on THELP all risks related to development of the Project, including
10 permitting, securing necessary grant funding, capital costs to complete, and
11 schedule (including completing all condition precedents needed for the EPA to
12 come fully into force for development of the Project).
13
- 14 • In the event that the EPA does not proceed, or it proceeds but the Project in-service
15 is delayed, the EPA retains YEC ability to sustain reliable service using existing
16 YIS resources plus rented diesel units as required for dependable capacity
17 requirements.
18
- 19 • The EPA specifies the timelines required for the Project to proceed in order to
20 secure access to these new renewable energy and dependable capacity resources
21 on a timely and cost effective basis.
22

23 As reviewed in Section 4.3 of the Submission, the EPA conditions precedent identify initial
24 risks associated with bringing the EPA into legal force. These risks have minimal if any
25 impact on YEC, on the rates for customers, or on the prudence of proceeding with the
26 EPA at this time. If the EPA is unable to proceed due to failure to complete its Conditions
27 Precedent YEC will know this outcome well before the end of 2022, with ample time to
28 proceed with rented diesel options as required for 2024/25 and subsequent years to
29 ensure reliability of service to customers while other permanent renewable options are
30 reviewed and developed. The fact that the Conditions Precedent remain unresolved at this
31 time does not preclude the Board from assessing the EPA as directed by the Minister
32 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 9.3 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 51 modeled water years (Appendix A, Table A1) assuming forecast Atlin BC Hydro load with battery for 2032 at 7.11 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 modeled water years would equal at least 14 GWh and be sufficient to enable a full 8.75 MW of capacity to be delivered to YEC at Jakes Corner for more

1 than 85% of the 75 or 76 days in the PWP, which is more than enough days to
2 cover all of the PWP period when minus 30°C or lower temperature has been
3 recorded at Whitehorse during the PWP period.

4

5 • Table A1 of the Submission confirms that the above outcome is expected even
6 when the Surprise Lake reservoir is not full in the prior October/November (based
7 on the historic water year modeled estimates), so long as the Existing Plant and
8 battery load requirement is at 7.11 GWh/year or less (load forecast for 2032).¹

9 • To assess sensitivity of dependable capacity to possible higher Existing Plant
10 loads, the following have been confirmed:²

11 o If Surprise Lake is full in the prior October, the ability to provide 14 GWh of
12 delivered energy to YEC at Jakes Corner (and the dependable capacity at
13 8.75MW provided for over 85% of the PWP days) is retained regardless of
14 possible Existing Plant and battery load level increases examined (up to 9
15 GWh per year total load).

16 o If Surprise Lake is not full in the prior October, it has been confirmed that
17 so long as the Existing Plant and battery load does not exceed 9 GWh/year,
18 water availability is expected to be adequate for LTA delivered energy to
19 YEC during the PWP to be at least 12 GWh, which is sufficient to enable a
20 full 8.75 MW of capacity to be delivered at POI for over 54 full days
21 (assuming the balance of PWP days at approximately 11% of 8.75 MW),
22 i.e., confirmed ability to accommodate at full capacity at least one two-week
23 cold temperature period plus at least 40 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.

1 **ISSUE:** Thermal displacement

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

5 **QUOTE:** “As reviewed in Section 3 below, the Amended EPA focuses on
6 energy delivery for the Winter Period (defined as January-May and
7 September-December inclusive). Expected Winter Period deliveries
8 to YEC per calendar year are 34.0 GWh LTA energy. Figure 2-3
9 below shows LTA Winter Project deliveries by month at Jakes
10 Corner, and the resulting LTA YIS thermal displacement benefits of
11 24.2 GWh/year at forecast 2024 YIS load after considering other
12 existing or expected renewable sources.”

15 **QUESTION:**

- 17 a) If 34.0 GWh is provided year-round and the thermal displacement is 24.2 GWh,
18 what is the cost of the remaining 9.8 GWh?

20 **ANSWER:**

22 **(a)**

24 The energy cost (price) is based on the LTA delivery of 34.0 GWh per year (with its related
25 annual variability) being estimated to displace 24.2 GWh/year of thermal generation. The
26 unit price is calculated to reflect that not all of this delivered energy will displace thermal.
27 This is clear from the calculations in column A of Table A3 of the Submission and further
28 explained in response to YUB-YEC-1-24.

30 YEC cost savings from EPA or other IPP deliveries relate to the resulting thermal
31 displacement. No YEC cost savings are derived from EPA or other IPP deliveries that do
32 not displace thermal generation.

34 The referenced long-term average (LTA) 34.0 GWh is for EPA deliveries provided only
35 during the defined Winter Period. It reflects the average deliveries over 51 modeled Atlin
36 water years. The LTA thermal displacement estimated to result from these EPA deliveries
37 reflects the average of 38 YIS water years. Figure 2-4 in YEC’s Submission highlights the

1 wide variance over the 38 YIS water years in forecast thermal displacement using 2024
2 YIS load forecasts.

3
4 The estimated LTA thermal displacement was used to develop the EPA energy price to
5 be paid for delivered energy. YEC is required under the EPA, subject to the Operating
6 Rules, to take all of the energy deliveries provided during the Winter Period (i.e., the 34.0
7 GWh of expected LTA winter deliveries). The EPA price paid per kWh for these deliveries
8 was determined based on the estimated resulting LTA thermal displacement:

- 9
- 10 • Using \$0.19/kWh (2024\$) as the expected cost saving for displaced thermal, the
11 24.2 GWh/year of expected thermal displacement from the EPA winter deliveries
12 were therefore estimated to provide YEC cost savings of approximately \$4.59
13 million per year (2024\$).
 - 14
 - 15 • The resulting EPA energy price payable for these winter deliveries was set to
16 equal the expected thermal displacement cost savings for YEC, i.e., the average
17 price paid for LTA 34.0 GWh of deliveries equals \$0.135/kWh or \$4.59 million
18 divided by 34.0 GWh.
 - 19

20 Table A3 of the Submission provides detailed calculations for the average EPA price
21 payable in 2024\$ for the 2024 load forecast (\$0.135/kWh) and for the 2035 load forecast
22 (\$0.097/kWh).

1 **ISSUE: Benefit of winter deliveries**

3 **REFERENCE: Application, Figure 2-3, page 5, PDF page 8**

5 **QUOTE:**

7 **QUESTION:**

9 a) For areas of the blue portions of Atlin deliveries that are above the red line in Figure
10 2-3, does that mean that YEC would take deliveries when there are no LTA
11 benefits? Why or why not?

13 **ANSWER:**

15 **(a)**

17 Yes. YEC will take deliveries under the EPA (as well as under other IPP agreements)
18 when there are no LTA benefits.

20 This will occur because, under the EPA, YEC is required to purchase all Atlin deliveries
21 during the Winter Period. This requirement reflects both the technical inability to dispatch
22 deliveries on anything less than a multiple day order period, and the Seller inability to
23 accept the financial risks related to payments being provided only when YEC achieves
24 thermal displacement.

26 The EPA pricing in the agreement is reduced to recognize that certain energy deliveries
27 have no thermal offsets. That is, the EPA energy price was set based on the average LTA
28 thermal displacement expected from winter deliveries. As reviewed in more detail in the
29 response to YUB-YEC-1-11, assuming \$0.19/kWh saving for thermal displacements, the
30 average EPA energy price for 2024 winter deliveries is only \$0.135/kWh rather than
31 \$0.19/kWh – reflecting the ratio of expected LTA thermal displacement to total expected
32 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 million. Grant funding of approximately \$150 million has been committed from the governments of the Yukon Territory 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% LNG¹ at 2024 cost of \$0.18/kWh and 10% diesel² 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).

1 was "...persuaded that only relying on rented diesel generators would be challenging and
2 would not be a reliable way of closing the capacity shortfall gap."⁴

3
4 **(b)**

5
6 YEC's dependable capacity requirement provides backup for the largest single
7 contingency event (N-1) disruption of generation supply. This currently results in
8 approximately 37 MW of backup based on possible disruption of the Aishihik Generating
9 Station supply. To require additional capacity to back up the EPA resource, or in fact any
10 other resource would effectively require double-redundancy or N-2 contingency planning.
11 However, there are certain risk mitigation protections in the EPA.

12
13 Section 4.3 of YEC's Submission reviews risks related to dependable capacity service
14 reliability.

15
16 **Construction and Commissioning** - Section 4.3 of the EPA provides that YEC may
17 proceed to rent diesel generating units for this Peak Winter Period (PWP) if THELP is
18 unable to confirm to YEC on or before June 1, 2024 the availability of Dependable Plant
19 Capacity for the first PWP, and no Dependable Capacity Payment will be payable by YEC
20 to THELP for the first PWP for Dependable Plant Capacity that was already provided by
21 such rented diesels.⁵

22
23 **Operations** - During subsequent operation of the Atlin Project after commissioning the
24 risk that dependable capacity is not provided as planned during a PWP varies materially
25 depending on when the issue is identified as well as its magnitude and duration:

- 26
27
 - Available evidence from 51 modeled water years and the SNC Lavalin analysis
28 (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."

1 an expected risk affecting Project ability to provide dependable capacity as
2 required during the PWP.

3

4 • During a PWP it is possible that disruptions affecting THELP's Plant may result in
5 short term disruptions to the delivery of dependable capacity. Such disruptions are
6 not expected to occur on any frequent basis, and would be unlikely to affect overall
7 YIS service reliability unless they are concurrent with an N-1 event during a cold
8 weather period.

9

10 • To address notification of other constraints on THELP's Plant capability regarding
11 dependable capacity, Section 6.2 of the Amended EPA requires as follows
12 throughout the Term: "If Seller becomes aware that it will not be able to provide
13 100% of the Dependable Plant Capacity Committed for the following Peak Winter
14 Period due to factors other than water availability to Surprise Lake, Seller will
15 provide, as soon as practicable, Notice to Buyer to permit Buyer when feasible to
16 make alternative arrangements."

17

18 o If such Notice is provided with sufficient time (i.e., by June prior to a PWP)
19 YEC would expect to be able to secure rental diesel capacity as required
20 to ensure reliable service for the coming PWP – and the Amended EPA
21 provisions would ensure that this capacity would be excluded from any
22 dependable capacity payments for that PWP.

23

24 o Otherwise, if YEC is unable to secure rental diesel capacity replacement
25 due to lack of time or other inability to secure rentals, there is a risk resulting
26 that YIS would have a N-1 dependable capacity shortfall for the affected
27 PWP. This same risk relates to all of YEC's facilities and is not expected to
28 be a material risk unless there is in fact an N-1 event during a cold weather
29 period during the affected PWP.

30 (c)

31 Yukon Energy's 10-Year Renewable Electricity Plan as summarized in Section 4.1.1 of
32 YEC's Submission, in Figure 4-1 and Table 4-1, provides the best available forecast on
33 thermal generation capacity that YEC will require to maintain N-1 capacity after electricity
34 deliveries under the EPA take effect in late 2024. These projections include YEC's non-
35 industrial peak load growth (as relevant for N-1 determinations) forecast to 2041/42 (in
36 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 8.75 MW. Without Moon Lake pumped storage, rented diesel requirements would be forecast to be reduced accordingly (ignoring any additional requirement for spares):
 - o In winter 2024/25, from 10 units to 5 units (reduction of 5 units)
 - o 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.

- 1 has occurred. The feasibility of this project is expected to be further clarified by the
- 2 time that EPA deliveries commence.

1 **ISSUE: Low water sequence**

2
3 **REFERENCE: Application, Figure 2-4, page 6, PDF page 9**

4
5 **QUOTE:**

6
7 **QUESTION:**

8
9 a) For the assumption for “Average for Low Water Sequence”, which is the solid red
10 line in Figure 2-4, explain how likely it is that Atlin can provide contracted electricity
11 deliveries at full levels to YEC if there are low water or drought conditions.

12
13 b) Would low water or drought conditions impact Atlin’s operations?

14
15 **ANSWER:**

16
17 **(a)**

18
19 The LTA winter deliveries from Atlin with the Amended EPA reflect full delivery during
20 winter months each year based on available water year information for the Atlin project
21 (51 modeled years) as provided in Table A1 of YEC’s Submission. The Amended EPA
22 does not “contract” for THELP to provide any specific minimum annual level of winter
23 energy deliveries (beyond providing what is available each Winter Period, subject to
24 Operating Rules controls and constraints) – and the payment provided for winter energy
25 deliveries each Year will be based on one set price per kWh delivered.

26
27 Figure 2-4 assumes LTA Atlin deliveries throughout the model range of YIS water years.
28 No model development has been feasible to date to assess potential correlation of a YIS
29 low water sequence with low water conditions at Atlin, and therefore no probability
30 assessment of that possible correlation can be provided at this time.

31
32 The Amended EPA energy pricing does not provide a separate a price for “firm” energy
33 deliveries (the first 23.4 GWh during the Winter Period in a calendar year, based on the
34 lowest recorded Atlin water year) from the price for “non-firm” energy deliveries (all energy
35 delivered above 23.4 GWh during the Winter Period in a calendar year).

1 Available analysis in Table A1 of Atlin EPA deliveries over the 51 modeled Atlin water
2 years indicates the following for Atlin water years with deliveries less than 90% of the 34,0
3 GWh/year LTA (i.e., below 30.6 GWh) used in Figure 2-4:

- 4
- 5 • 4 years below 26 GWh (1985 at 23.4 GWh, 1976 at 24.4 GWh, 1973 at 25.5 GWh
6 and 2008 at 25.6 GWh).
- 7 • 4 years above 26 GWh, and below 27 GWh (2013 and 2020 at 26.10 GWh, 2019
8 at 26.6 GWh and 1996 at 26.7 GWh).
- 9 • 3 years above 27 GWh, and below 28 GWh (1978 at 27.3 GWh, 1995 at 27.4GWh
10 and 1993 at 27.9 GWh).
- 11 • 3 years between 30.0 and 30.6 GWh (2017 at 30.0 GWh, 1997 at 30.3 GWh and
12 1990 at 30.6 GWh).

13
14 **(b)**

15
16 Low water or drought conditions at Atlin will reduce annual energy deliveries, but are not
17 expected to lower the dependable capacity of 8.75 MW provided by the EPA.

18
19 As reviewed in Section 2.2 of the EPA Submission, expected energy deliveries during
20 each Peak Winter Period (PWP), based on the Project's Surprise Lake storage and its
21 more than 50 modeled water years,¹ will enable a full 8.75 MW of capacity to be delivered
22 to YEC each year at Jakes Corner for over 85% of the 75 or 76 days in the PWP. This is
23 more than enough days to cover the 20 or less days of the PWP period when minus 30°C
24 or lower temperature has been recorded at Whitehorse.²

¹ See Table A1 of the Submission.

² YEC's winter peak non-industrial load forecast assumes -38°C, with approximately 8 MW load added by an average daily temperature drop below -30°C. 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 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.

1 **ISSUE:** **Project capital costs**

3 **REFERENCE:** **Application, page 6, PDF page 9**

5 **PREAMBLE:** Project capital costs have been estimated to date at approximately
6 \$240 million.

8 **QUESTION:**

- 10 a) On a best estimate basis, provide the capital cost breakdown for this project
11 between generation (production) costs and transmission costs.

13 **ANSWER:**

15 **(a)**

17 The Project is being developed by THELP, and YEC is therefore only aware of capital cost
18 estimates and breakdowns as provided by THELP. Section 2.1(d)(iii) of the EPA requires,
19 as a Condition Precedent to be satisfied, by May 31, 2022, that THELP will have submitted
20 to YEC a detailed funding plan that includes independent third party estimates of capital
21 costs as well as sources of grant funding from governments and debt financing third party
22 lenders.

24 The \$240 million estimate (2024\$) for Project capital costs reflects information provided
25 to YEC by THELP in March 2022, with adjustment to reflect the revised Project design
26 and the latest estimates for other costs. YEC has not received any detail on the breakdown
27 of these updated costs – however, based on prior cost allocation information and
28 assuming that the latest cost increases relate to the generation plant elements, the \$240
29 million total would appear to include approximately \$170 million for the generation plant,
30 approximately \$53 million for THELP transmission/ substation plant elements, and
31 approximately \$17 million for YEC/AEY System Upgrades.

33 YEC understands that the above estimate will be revised by THELP as required based on
34 review with its owner's engineer and selected contractors.

1 **ISSUE: Grant funding**

3 **REFERENCE: Application, page 6, PDF page 9**

5 **QUOTE:** "Grant funding of approximately \$150 million has been committed from
6 the governments of the Yukon Territory and Canada to support the
7 economics of the Project."
8
9

10 **QUESTION:**

- 11
- 12 a) What parts of the project would B.C. government funding cover?
- 13
- 14 b) What parts of the project would Yukon government funding apply to?
- 15
- 16 c) What parts of the project would federal government funding apply to?
- 17
- 18 d) Please describe each of the grants, the amounts of each of the grants, and the
19 current status and completion dates of each of the grant applications.
- 20
- 21 e) Please explain the funding source for the \$90 million in costs for the project not
22 covered by government grants.
- 23

24 **ANSWER:**

25

26 **(a), (b), (c) and (d)**

27

28 The Project is being developed by THELP, and YEC is therefore only aware of THELP's
29 funding source information as provided by THELP or as provided in joint discussions with
30 government grant funders. We are not currently aware of any grant funding being allocated
31 only to specific parts of the project rather than to the overall project. The Yukon
32 government has committed \$50 million to the Atlin Hydro Expansion Project and Canada
33 has committed \$100 million to the development phase (other funds are being provided
34 during the planning phase). Any grant funding to be provided by British Columbia
35 continues to be under discussion, and details cannot be appropriately provided at this
36 time.
37

1 Section 2.1(d)(iii) of the EPA requires, as a Condition Precedent to be satisfied by May
2 31, 2022, that THELP will have submitted to YEC a detailed funding plan that includes
3 independent third party estimates of capital costs as well as sources of grant funding from
4 each government and debt financing third party lenders.

5
6 **(e)**

7
8 YEC understands that THELP is in discussion with the Canadian Infrastructure Bank (CIB)
9 for debt financing related to the Project at an interest rate of 1%. YEC does not have
10 further information at this time on other funding sources beyond government grants and
11 CIB.

1 **ISSUE: Interconnection Agreement**

3 **REFERENCE: Application, page 8, PDF page 11**

5 **QUOTE:** "The Project will also include upgrades as required to connect the
6 THELP's Plant to the YIS (defined in the Amended EPA as "Buyer-
7 AEY System" and "Buyer-AEY System Upgrades"). Final scoping for
8 these upgrades (with planning level cost estimates) is to be included
9 in the Buyer-AEY System Interconnection Study Report that is
10 currently being concluded as part of the Interconnection Agreement
11 between THELP, YEC and AEY."
12

13 **QUESTION:**

- 14
- 15 a) When is the Buyer-AEY System Interconnection Study Report due, and when will
16 those costs be known?
17
- 18 b) Is there a cost threshold for this part of the project at which the project will not be
19 viable or otherwise not proceed?
20
- 21 c) From the Yukon/BC border to Jakes Corner, how many potential electricity users
22 will connect to the system?
23
- 24 d) Are those users customers of THELP or YEC?
25
- 26 e) What First Nation settlement lands and traditional territories would be affected [sic]
27 the Atlin-Jakes Corner infrastructure, and what is the extent of
28 consultation/accommodation to date?
29

30 **ANSWER:**

31
32 **(a)**
33

34 The Buyer-AEY System Interconnection Study report forms part of the Interconnection
35 Agreement. The Condition Precedent date for the Interconnection Agreement to be
36 executed has been extended to May 31, 2022. Please see response to YUB-YEC-1-9(a)
37 for current information on system upgrades and related cost estimates.

1 **(b)**

2
3 No cost threshold has been specified by THELP for these YEC and AEY system upgrades.
4

5 **(c) and (d)**

6
7 No electricity users will connect to the system from the line to be developed and owned
8 by THELP between the Yukon/BC border to Jakes Corner.
9

10 **(e)**

11
12 The THELP owned and developed Project facilities in Yukon between the BC/Yukon
13 border and Jakes Corner are in the traditional territory of the Carcross Tagish First Nation,
14 but do not affect any First Nation settlement lands.
15

16 Project facilities in British Columbia are in the traditional territory of the Taku River Tlingit
17 First Nation.
18

19 THELP is responsible for consultation/ accommodation related to the Project. YEC is not
20 able to advise on the specifics to date regarding these activities.

1 **ISSUE: Dependable Plant Capacity Tests**

2
3 **REFERENCE: Application, page 9, PDF page 12**

4
5 **QUOTE:** “Dependable Plant Capacity Tests at THELP’s COD - overall
6 Dependable Plant Capacity delivered to YEC at the POI, as
7 confirmed by these tests, cannot be less than 8.5 MW and not more
8 than 8.75 MW.”
9

10 **QUESTION:**

11
12 a) Please explain the significance of the upper limit of 8.75 MW.
13

14 **ANSWER:**

15
16 **(a)**

17
18 An upper limit was set to ensure that the plant could be operated during the Peak Winter
19 Period as required to provide dependable capacity, given information on available water
20 availability as reviewed in Table A1 of the Submission. If for some reason THELP had
21 opportunity to provide a higher delivered capacity, an amendment of this provision would
22 be required – and any such amendment would depend on THELP confirming that the Atlin
23 plant could be operated during the Peak Winter Period as required to provide dependable
24 capacity, given information on water availability.
25

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

1 **ISSUE: Operating rules**

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

5 **QUOTE:** "Operating Rules for Seller's Plant (Schedule D of Amended EPA) -
6 the Amended EPA requires Seller and Buyer to coordinate and
7 schedule the delivery of Delivered Energy and Dependable Plant
8 Capacity (each defined at the POI for delivery by Seller to Buyer) under
9 the Operating Rules as set out in Schedule D attached to the Amended
10 EPA. The Operating Rules include provisions that are focused on
11 maximizing hydro storage and its effective use at YEC's direction to
12 provide dependable capacity during the PWP and to displace thermal
13 generation throughout the Winter Period."
14

15 **QUESTION:**

- 16
- 17 a) Please provide the details and principles YEC will use in determining its merit order
18 for dispatching generation.
19
- 20 b) Where will the Atlin hydro expansion project's electricity be placed in the merit
21 order?
22

23 **ANSWER:**

24
25 **(a) and (b)**
26

27 SOP IPP contracts are take-or-pay arrangements; therefore, these IPP contracts are
28 dispatched first in the generation stacking order, followed by YEC hydro and thermal
29 assets. The revised Atlin hydro expansion project and Amended EPA, however, provide
30 YEC with materially enhanced dispatchability – and therefore this project will be
31 dispatched when feasible after the SOP IPP contracts, after YEC Whitehorse and Mayo
32 hydro assets, and before YEC Aishihik hydro and thermal assets. Note that the Atlin plant
33 is intended to be shut down for the summer months, unless YEC specifically requests
34 summer energy (which would only happen when thermal generation was otherwise
35 expected on the YIS).

1 **ISSUE: Commercial terms**

3 **REFERENCE: Application, page 11, PDF page 14**

5 **QUOTE:** “2. Payment for Winter Energy that displaces forecast thermal
6 generation: YEC will only pay for winter energy based on prices
7 determined based on expected displacement of YEC’s forecast thermal
8 fuel generation costs at long-term average (“LTA”) renewable sources
9 for the YIS and the Project.”

10 “3. Delivery of all Winter Energy available: while YEC will only pay for
11 winter energy that is expected to displace LTA forecast thermal
12 generation, YEC will take delivery each winter season (Sep-May) of all
13 available energy that the Project is able to generate.”

14 “4. Thermal Benchmark Pricing: the 2024 benchmark prices paid under
15 the Amended EPA are based on \$0.19/kWh for energy that displaces
16 thermal generation (based on blended thermal generation LNG and
17 diesel fuel costs) and \$200/kW per year for the levelized cost of
18 capacity (capital and non-fuel O&M) of permanent new greenfield
19 thermal generation assets. The benchmark prices after 2024 are
20 assumed to escalate at 50% of CPI for energy and 100% of CPI for
21 dependable capacity.”

22 “5. Payment for Capacity: rather than paying for actual dependable
23 capacity provided by the Project, YEC will pay for Dependable Plant
24 Capacity Committed over each Peak Winter Period, based on the
25 outcome of a capacity test completed each December at the beginning
26 of each winter period. A mechanism is included for YEC to recoup any
27 shortfalls in actual dependable capacity delivered each winter period
28 through deductions from the additional revenue opportunities/upside
29 opportunities for THELP (see item 7 below).”

31 **QUESTION:**

- 32
- 33 a) In paragraph 2 of the above quote, explain in detail what is meant by “forecast
34 thermal fuel generation costs at long-term average renewable sources” and how it
35 applies in the context of the quote.
- 36
- 37 b) How is the thermal displacement amount determined?
- 38
- 39 c) What happens if thermal fuel generation costs are lower than LTA?

- 1
- 2 d) What happens if thermal fuel generation costs are higher than LTA?
- 3
- 4 e) In paragraph 3 of the above quote, what are the implications of this provision
- 5 relative to the amount of thermal generation that YEC would otherwise require
- 6 during the winter months?
- 7
- 8 f) In paragraph 3 of the above quote, does the term “Delivery of all Winter Energy”
- 9 create a situation where YEC will spill water at its own hydro facilities without
- 10 generating electricity because it is taking energy based on the Atlin project?
- 11
- 12 g) Is the result that any energy delivered in excess of LTA forecast thermal generation
- 13 will effectively be delivered at no cost?
- 14
- 15 h) In paragraph 4 of the quote above, does the blended LNG and diesel fuel costs for
- 16 generation closely reflect the actual costs for usage of those generation sources?
- 17
- 18 i) Please file any existing documents relating to the costing model for permanent new
- 19 greenfield thermal generation assets, including any form of business case
- 20 analysis, including comparison with rented diesel generators.
- 21
- 22 j) Show detailed calculations of how the \$0.19/kWh and \$200/kW were derived. In
- 23 the response, list all assumptions made in the calculations.
- 24
- 25 k) Why are benchmark prices assumed to escalate instead of relying on previous
- 26 year escalation rates?
- 27
- 28 l) Is capacity considered a fixed cost? Please explain.
- 29
- 30 m) If capacity is considered a fixed cost, why is it escalated by CPI?
- 31
- 32 n) Explain why committed capacity is used and not actual capacity. Please explain
- 33 why committed capacity is preferable to actual capacity given, for example, that
- 34 price and revenue would be more accurate using actual capacity.
- 35
- 36 o) How does the use of committed capacity benefit both YEC and Yukon ratepayers?
- 37

1 p) Does the mechanism in paragraph 5 result in any actual cash recovery from
2 THELP (or deferral of YEC payments to THELP), and if so, what length of time
3 would it take to recover any shortfalls?
4

5 **ANSWER:**
6

7 **(a) through (p)**
8

9 The question focuses on four specific “key principles” relevant to YEC as purchaser, as
10 noted in Section 3.4.1 of the Submission. The principles guided the negotiation of the EPA
11 commercial terms – however, specific questions as posed in this IR regarding EPA
12 commercial terms require review of the EPA terms. The following response accordingly
13 addresses the applicable EPA terms.
14

15 **Energy Price and Payment for Delivered Energy during Winter Period**
16

17 Questions (a) through (h) as well as (j and k) address principles and terms for the EPA
18 energy price for delivered energy during the Winter Period.
19

20 Overall, in Principle 2 YEC required that EPA energy prices for winter period delivered
21 energy be based on YEC forecast thermal fuel cost savings as assessed at long-term
22 average (LTA) conditions for both the Atlin delivered energy and the other forecast YIS
23 renewable generation sources.
24

25 In order to determine the required YEC thermal fuel cost savings, consistency is required
26 with OIC 2021/16 direction that YEC’s forecast fuel costs must be based on long term
27 average renewable generation when setting YEC rates – and that variances in actual
28 thermal generation from LTA thermal generation are to be addressed by a low water
29 deferral account. In summary, YEC costs and rates for thermal generation are based on
30 LTA renewable generation sources.
31

32 The forecast approach is also necessary to set EPA prices that will provide the Seller
33 sufficient certainty on revenue to prove financial viability, i.e. this certainty is required now
34 to ensure a “bankable” project.
35

36 Forecast thermal displacement volumes and costs (2024\$) for 2024 load forecast and
37 2035 load forecast, at LTA Atlin deliveries and low water year deliveries, are provided in

1 Table A3 of YEC's amended Submission. The volume of thermal displacement is
2 calculated by modelling the YIS system using YECSIM to simulate thermal generation
3 both with and without Atlin under 38 water years for 2024 and 2035 YIS forecast loads.
4 The Table A3 process is summarized below using as an example Table A3 column A
5 dealing with the 2024 YIS load forecast:

- 6
- 7 • In Table A3 for the 2024 load forecast, the model estimates:
 - 8 o in column A that LTA winter deliveries of 34.0 GWh result in LTA thermal
 - 9 displacement of 24.181 GWh (displacement at 71.2% of EPA deliveries);
- 10
- 11 • The estimated ratio is then applied to the YEC forecast blended fuel cost of 19
- 12 cents per kWh to get (row 10) the EPA winter price of 13.5 cents/kWh for LTA
- 13 deliveries.
- 14
- 15 • Based on the assumptions as presented, YEC believes that this approach
- 16 effectively ensures, within a reasonable range, that the utility will not pay for energy
- 17 that does not offset forecast thermal displacement.
- 18

19 These 2024\$ prices apply throughout the 40-year EPA term, subject (as is the case for
20 SOP IPP prices) to annual escalation at 50% of CPI.

21

22 The response to YUB-YEC-1-13(a) provides the detailed calculations and assumptions
23 regarding the (2024\$) \$0.19/kWh blend fuel price assumed for 2024 thermal energy
24 displacement cost saving estimates. The 90%/10% assumed mix of LNG and diesel
25 generation reflects YEC assumptions to date for GRA filings and is intended to reflect
26 reasonably expected LTA thermal generation rather than actual generation in any specific
27 year. Escalation of this forecast blend fuel energy price after 2024 at 50% of CPI reflects
28 the same approach applicable to the SOP IPP price escalations.

29

30 Under Principle 3, YEC accepts that they will purchase all energy delivered during the
31 Winter Period, subject to the constraints and directions in the Operating Rules. The above
32 Table A3 analysis shows how the EPA energy prices with this requirement are based on
33 forecast LTA thermal displacement, taking into account purchased deliveries that do not
34 displace thermal generation and increase water spill at YEC hydro facilities. See also
35 YUB-YEC-1-11 and YUB-YEC-1-12 for additional analysis.

1 When coupled with the need to set EPA prices based on forecasts, there is cost risk
2 created under Principle 3 because actual conditions will in all likelihood vary from the
3 assumed forecasts. This risk is unlikely to result in material impact on YEC costs as
4 supported in detail in Section 4.3 of YEC's Submission (see Operations, subsection 1 on
5 Delivered Electricity). This conclusion reflects the ability to adjust YEC thermal generation
6 in response to changes in Atlin deliveries, and the setting of the EPA price based on
7 forecast thermal generation displaced.

8
9 Another risk is related to YIS loads, other renewable energy resources or fuel costs for
10 thermal generation being different than assumed for setting EPA energy prices. These
11 YIS forecast condition risks affect any new YEC resource commitment made for long-term
12 energy generation supplies. Although such variances are likely, YEC's Submission (based
13 on analysis provided at section 4.3 "Operations") that these risks only affect net YEC costs
14 for the EPA relative to thermal energy generation, and remain reasonable in the context
15 of YIS resource planning.

16 17 **Dependable Capacity Price and Payment for PWP**

18
19 Questions (i) through (p) address principles and terms for the EPA capacity price for
20 dependable capacity provided during a Peak Winter Period (PWP).

21
22 The assumptions and references for the \$200/kW (2024\$) EPA capacity price
23 determination based on levelized cost of capacity (LCOC) for new greenfield diesel are
24 reviewed in detail in response to YUB-YEC-1-13(a). As reviewed in that response, the
25 Board in its report on the BESS Project noted that rented diesels would not be a reliable
26 way of closing the capacity shortfall gap. Rented diesel costs were therefore not
27 considered in the setting of the EPA capacity price.

28
29 The LCOC cost benchmarks referenced for new greenfield diesel include capital and non-
30 fuel O&M costs (i.e., fuel costs are excluded). In the case of an actual new diesel plant,
31 once built and in-service the capital cost would be "fixed" and added to YEC rate base
32 with annual depreciation and return on rate base expenses added to YEC annual costs –
33 annual non-fuel operating costs, however, would vary and normally escalate over the
34 years of operation. In contrast to such actual annual cost impacts from a new diesel plant,
35 the LCOC benchmark established one present value amount per kW-yr for year 1 of
36 operation to reflect estimated "real" (i.e., absent inflation) capital and non-fuel O&M over
37 the life, and then assumes that this amount escalates at inflation over the project life.

1
2 The resulting LCOC amount per KW-yr was estimated starting in 2019 in the benchmark,
3 and the estimate assumed escalation of this benchmark at CPI throughout the assumed
4 life of the facility (as well as escalation as needed to adjust for an in-service date later than
5 2019). These factors explain why the EPA capacity price for 2024 assumed 2%/yr inflation
6 escalation from 2019 to 2024, and also provided for ongoing escalation at CPI during the
7 EPA term.

8
9 The concept of Dependable Plant Capacity Committed for determining initial payments
10 was adopted as a result of negotiation to address the following considerations needed to
11 allow the EPA to be concluded:

12
13 1. **Seller Financial Risk** - THELP required a firm capacity revenue amount for each
14 year to assist in securing its financing, and was not prepared to proceed with these
15 initial payments being subject to variance based on actual performance. THELP
16 did agree, however, to the December capacity test for each year to confirm
17 Dependable Plant Capacity Committed for each PWP based on this test. This
18 measure addressed basic risks related to Seller Plant conditions over time.

19
20 2. **Operational Risk** - YEC's review of available water (Table A1 of Submission) as
21 well as the Amended EPA Operating Rules confirmed expected ability under all
22 likely water conditions to secure the needed dependable capacity during the PWP.
23 During a PWP it is possible that disruptions affecting THELP's Plant may result in
24 short term disruptions to the delivery of dependable capacity. Such disruptions are
25 not expected to occur on any frequent basis, and would be unlikely to affect overall
26 YIS service reliability unless they are concurrent with an N-1 event during a cold
27 weather period.

28
29 In order to proceed, YEC secured the Dependable Capacity Excess Payment (DCEP)
30 mechanism to recover excess Dependable Capacity Payments (DCP) due to shortfalls
31 in actual dependable capacity delivered each PWP. Recoveries are contingent on
32 THELP being eligible for additional payments in future years beyond the EPA prices –
33 but YEC recoveries are to occur before any THELP additional payments would be
34 made for higher-than-forecast loads after 2034 or any carbon tax charges applicable
35 to YEC.

1 In summary, the use of committed capacity enabled all parties to proceed with work to
2 advance the Project in order to secure the forecast benefits for both YEC (and ratepayers)
3 and THELP.

4

5 The mechanism in Principle 5 in the referenced quote would reduce (rather than defer)
6 YEC cash payments to THELP. YEC is not able to provide any assessments of time
7 requirements, beyond noting that recoveries related to Additional Payments (linked to
8 Added Load on the grid) cannot occur before 2035.

1 **ISSUE: Buyer-AEY System Constraint**

3 **REFERENCE: Application, page 12, PDF page 15**

5 **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."

16 **QUESTION:**

- 18 a) Please provide further explanation of when YEC will not be responsible for
19 payment in the Buyer-AEY System Constraint in Article 6. In your response,
20 provide a numerical example of how the Monthly Constraint Energy will be
21 calculated.
- 23 b) In what circumstances will YEC pay for unplanned outages in THELP facilities
24 through the Monthly Constraint Energy in Schedule F?
- 26 c) Would YEC be required to pay for energy not received under the Buyer-AEY
27 System Constraint?
- 29 d) Would THELP have any financial liability to YEC for failing to deliver contracted
30 energy due to reasons other than low water conditions? If not, what consequential
31 impacts would there be for Yukon ratepayers?

33 **ANSWER:**

35 **(a)**

37 "Monthly Constraint Energy" as defined in Schedule F of the EPA only occurs when YEC
38 is responsible for payment regarding a Non-Permitted System Constraint, i.e., there is no

1 example possible of how the Monthly Constraint Energy would be calculated when YEC
2 is not responsible for payment in the Buyer-AEY System Constraint in Article 6.

3
4 As defined in the EPA, a Buyer-AEY System Constraint “means any disconnection of
5 Seller’s Plant from Buyer-AEY System, or any outage, suspension, constraint, or
6 curtailment in the operation of Buyer-AEY System preventing or limiting deliveries of
7 Delivered Energy at the POI or within the Buyer-AEY System or any direction from Buyer
8 to Seller to reduce generation of Seller’s Plant as a result of any outage, suspension,
9 constraint, or curtailment in the operation of the Buyer-AEY System.”

10
11 Section 6.5 provides that Buyer will have no liability for a Buyer-AEY System Constraint
12 (or be in breach of Sections 6.3 or 8.2) unless it is a Non-Permitted System Constraint as
13 defined in Section 6.5. To be a Non-Permitted System Constraint for which YEC will pay
14 the Monthly Constraint Energy calculated for the relevant month under Schedule F, the
15 Buyer-AEY System Constraint must:

- 16
- 17 • Prevent Seller to deliver Delivered Energy that Seller is permitted to deliver under
18 this EPA.
 - 19
 - 20 • Be solely the result of a continuous Buyer-AEY System Constraint which exceeds
21 30 minutes in duration and is not caused by (a) Buyer-AEY Planned Outage, or
22 (b) Seller, Seller’s Plant, or anything on Seller’s side of the POI.
 - 23
 - 24 • Not be subject to exemptions set out in Section 6.5 when Buyer will not be required
25 to pay for any Monthly Constraint Energy¹.
 - 26

27 An example of how the Monthly Constraint Energy will be calculated is provided below,
28 based on an aggregate of the Constraint Shortfall Energy for each Non-Permitted System
29 Constraint event during a month:

- 30
- 31 1. Assume 2 separate Non-Permitted System Constraint events occur as follows
32 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.

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

- 3 a. Event #1: 1 hour when 8,750 kWh Delivered Energy was expected to be
4 provided; and
5 b. Event #2: 100 hours when 875,000 kWh Delivered Energy was expected
6 to be provided.

7
8 2. Assume that the following reductions in such expected Delivered Energy are
9 reductions that Seller takes, or is reasonably able to take, in response to the Non-
10 Permitted System Constraint events to reduce or shut down water deliveries in the
11 Powerhouse:

- 12 a. Event #1: Reduction to 1MW for last 15 minutes of the hour, resulting in a
13 reduction capability of $2,187.5 \text{ kWh} = 15/60 * 8,750$.
14 b. Event #2: Determination that in response to the Non-Permitted System
15 Constraint the Seller was able to shut down water deliveries in the
16 Powerhouse after 1 hour, resulting is a reduction capability of $866,250 \text{ kWh}$
17 $= 99 * 8,750$.

18
19 3. The Monthly Constraint Energy for January will then equal 392,000 kWh based on
20 the aggregate of the following Constraint Shortall Energy for the two Non-Permitted
21 System Constraint events during the month:

- 22 a. Event #1: Constraint Shortfall Energy equals $6,562.5 \text{ kWh} = (8,750 -$
23 $2,187.5)$
24 b. Event #2: Constraint Shortfall Energy equals $8,750 \text{ kWh} = (875,000 -$
25 $866,250)$.

26
27 **(b)**

28
29 There are no circumstances related to Monthly Constraint Energy when YEC will pay for
30 unplanned outages in THELP facilities. As reviewed in response to "a" above, Section 6.5
31 of the EPA specifically excludes consideration of events on the Seller's side of the POI or
32 the result of operation of Seller's Plant in a manner inconsistent with Section 3.2 of the
33 EPA.

34
35 **(c)**

1 Yes, provided that such energy qualifies as Monthly Constraint Energy (see “a” above -
2 the example shows 15,312.5 kWh that would need to be paid for by YEC).

3
4 **(d)**

5
6 The question asks about “contracted energy”. Overall, the EPA does not generally impose
7 financial liabilities (other than reduced payments for the reduced energy deliveries) on
8 THELP for failure to deliver expected energy deliveries for reasons other than low water
9 conditions.² As reviewed in section 4.3 of YEC’s Submission (under Operations, Delivered
10 Energy), the risk of a material impact on YEC costs, customer rates or reliability of service
11 to customers from actual EPA delivered energy being lower than expected deliveries is
12 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.

1 **ISSUE: Historical records**

2
3 **REFERENCE: Application, footnote 34, page 22, PDF page 25**

4
5 **QUOTE:** “See Section 2.1.3 of this Submission. The LTA energy generation
6 estimate for the Project deliveries to YEC was prepared by SNC
7 Lavalin, retained by THELP, based on modeled water year flows as
8 reviewed in Appendix A, Table A1. The Project LTA energy
9 generation in Appendix A, Tables A1 and A3 for winter deliveries to
10 YEC at Jakes Corner reflects the average Atlin Project hydro
11 generation during the Winter Period (Jan. 1 to May 31, Sept. 1 to
12 Dec. 31) for all modeled water years. (Although Winter Period
13 includes period to May 31, the LTA energy delivery at 34.0 GWh was
14 modeled to May 15 to exclude energy from freshet.) The
15 transmission losses between the Atlin generation location and
16 delivery point at Jakes Corner is estimated to be at around 2.7%.
17 Additional losses of 4.5% are added that reflect losses on the YIS
18 system for estimated energy delivered from Jakes Corner to YEC’s
19 substation S150 at Whitehorse (these added losses take into
20 account the material portion of the Delivered Energy expected to be
21 used to supply customer loads on the southern Yukon AEY System
22 and assumes that AEY System Upgrades will result in continuation
23 of past average losses on the AEY System despite the material
24 increases in energy being transmitted on this system).”

25
26 **QUESTION:**

- 27
28 a) [Why are historical water records from 1994-2014 not included in the LTA energy
29 generation estimate?] *NTD: Original question no longer reflects the Submission.*
30
31 b) How accurate is the assumption that, with higher load, the assumed AEY System
32 Upgrades will result in the continuation of past average losses? Please explain the
33 basis for the assumption.
34

35 **ANSWER:**

36
37 **(a)**
38

1 Appendix A, Table A1 in the Amended Submission includes 51 modeled water years from
2 1970 to 2020. Therefore 1994-2014 is now included.

3
4 **(b)**

5
6 The 4.5% losses assumed for AEY transmission reflect historical information, the required
7 AEY System Upgrades, and Delivered Energy expected to be used for AEY customers on
8 the southern Yukon AEY System. Variances are expected after AEY System Upgrades
9 and addition of the Atlin deliveries. However, the AEY design for System Upgrades
10 assumes Atlin deliveries at the 8.75 MW maximum Atlin project delivery at Jakes Corner
11 and reflects the need to ensure expected AEY losses do not exceed 8.8%. Final selected
12 AEY Systems Upgrades design and Atlin load will affect the extent to which actual losses
13 are materially below the 8.8% design limit.

1 **ISSUE: EPA prices and energy deliveries**

3 **REFERENCE: Application, page 28, PDF page 31**

5 **QUOTE:** "The EPA prices are sensitive to firm energy versus non-firm energy
6 deliveries over the year – a factor which will tend to reduce cost
7 impacts for YEC from variances in actual versus LTA costs related
8 to EPA energy deliveries." *NTD – This quote has been deleted from*
9 *the Amended Submission.*

11 **QUESTION:**

13 a) Please provide further explanation on EPA prices and sensitivity because of
14 deliveries.

16 b) How would the factor work?

18 **ANSWER:**

20 **(a) and (b)**

22 As summarized in Table 3-1 of the Submission, the winter energy prices in the Amended
23 EPA are in 2024\$. One price is provided for 2024-2034 and another price for 2035 and
24 the balance of the Amended EPA Term, based on LTA Delivered Energy. These prices
25 escalate after 2024 at 50% of CPI and apply to all Delivered Energy and Monthly
26 Constraint Energy during the Winter Period in each Year, i.e., unlike the Original EPA, the
27 Amended EPA does not provide for separate firm and non-firm energy prices during the
28 Winter Period in each Year.

- 1 Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for
- 2 determining these firm and non-firm energy prices. Further explanation is provided in YUB-
- 3 YEC-1-11 and YUB-YEC-1-12.

1 **ISSUE: Water Storage Savings**

2
3 **REFERENCE: Application, Appendix A, Figure A2-1, page A-5, PDF page 40**

4
5 **QUOTE:**

6
7 **QUESTION:**

8
9 a) Figure A2-1 shows Water Storage Savings of 4.7 GWh/yr. Explain what this value
10 relates to and how that amount was determined.

11
12 **ANSWER:**

13
14 **(a)**

15
16 Water Storage Savings represents the value of thermal displacement avoided due to EPA
17 deliveries enabling added hydro storage on the YIS. It is distinguished from thermal
18 displacement that occurs directly due to EPA deliveries. As shown in Figure A2-1, total
19 LTA thermal displacement of 24.2 GWh/year for the 2024 load is the total resulting from
20 direct thermal displacement (19.5 GWh) and water storage savings thermal displacement
21 (4.7 GWh).

22
23 As noted in Table A3, LTA thermal displacement has been estimated based on YECSIM
24 model simulation runs for 38 water years. Key assumptions are noted in this table.

1 **ISSUE: Firm Winter Energy Price**

2
3 **REFERENCE: Application, Appendix B, footnote 16, page B-10, PDF page 54**

4
5 **QUOTE:** "Section 8.2 of the Amended EPA provides for monthly payment of
6 the Winter Energy Price for Delivered Energy and Monthly
7 Constraint Energy during the Winter Period."
8

9 **QUESTION:**

- 10
11 a) Please provide the basis for the statement in the above-quoted footnote.
12
13 b) Please explain the difference between "firm winter energy" and "non-firm winter
14 energy".
15
16 c) Is all pricing based on assumed low-flow water years? Please explain why or why
17 not.
18

19 **ANSWER:**

20
21 **(a)and (b)**

22
23 As summarized in Table 3-1 of the Submission, the winter energy prices in the Amended
24 EPA are in 2024\$. One price is provided for 2024-2034 and another price for 2035 and
25 the balance of the Amended EPA Term, based on LTA Delivered Energy. These prices all
26 escalate after 2024 at 50% of CPI and apply to all Delivered Energy and Monthly
27 Constraint Energy during the Winter Period in each Year, i.e., unlike the Original EPA, the
28 Amended EPA does not provide for separate firm and non-firm energy prices during the
29 Winter Period in each Year.
30

31 **(c)**

32
33 No pricing in the Amended EPA is based on assumed low flow water years at Atlin. The
34 Amended EPA winter energy pricing is based on LTA water availability at Atlin.
35

- 1 Tables A3-1 and A3-2 of the Submission review the calculations and assumptions for
- 2 determining these firm and non-firm energy prices. Further explanation is provided in YUB-
- 3 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 71.2% of all winter deliveries in these years).”

QUESTION:

a) Please explain how the 71.2% estimate was determined.

ANSWER:

(a)

The referenced quote applies to a Carbon Charge during the years 2024 to 2034. Based on Table A3 analysis for this period, the 71.2% equals the expected LTA thermal displacement from winter Amended EPA deliveries (24.181 GWh at row 5) divided by LTA EPA deliveries (34.0 GWh at row 1). Similarly, for the years 2035 and the balance of the Amended EPA term, this percentage is adjusted to 50.9% (17.289/34.0).

ISSUE: Alternatives to the project

REFERENCE: YEC 2016 Resource Plan Part 2, page 5-31, PDF page 3

QUOTE:

1 Table 5-27. Small Hydro Resource Option Technical and Financial Attributes

Annual Energy	Firm Energy	Installed Capacity	Dependable Capacity	Levelized Cost of Energy	Levelized Cost of Capacity	Project Life	Lead Time	Dispatchable
GWh/yr	GWh/yr	MW	MW	\$/kWh	\$/kW-yr	Years	Years	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:

- Please explore the financial ramifications for the Yukon ratepayers for the projects Drury Lake, Atlin/Pine Creek and Anvil Creek.
- Would the energy produced by a Yukon Consortium for a project located in Yukon fall under OIC 2019/25?
- In financial terms, what is the difference between this EPA and projects that would fall within OIC 2019/25?

1 **ANSWER:**

2
3 **(a)**

4
5 The table provided in the preamble is for small hydro projects reviewed in YEC's 2016
6 Resource Plan. Since then, YEC updated the small hydro resource options in the 10-Year
7 Renewable Electricity Plan.

8
9 For the 10-Year Renewable Electricity Plan YEC engaged Knight Piésold Ltd. (KP) to
10 update and further develop a desktop review of the potential hydroelectric projects in
11 Yukon and northern BC. This study resulted in a refined and updated list of five small
12 hydroelectric projects of interest, Atlin and four others, with capacities ranging from 8 MW
13 to 13 MW and with four of the five having storage capabilities.

14
15 Table 3, Refined List of Future Potential Resource Options, of the 10-Year Renewable
16 Electricity Plan provides an updated list of small hydro options [the technical report is
17 available at YUB-YEC-1-32, Attachment 1].

18
19 To date the review of the referenced small hydro projects by Yukon Energy were limited
20 to the desktop level pre-feasibility assessments conducted for 2016 Resource Plan and
21 10-Year Renewable Electricity Plan.¹ At this time, the financial ramifications to Yukon
22 ratepayers is limited to the cost of those studies. Potential future financial ramifications to
23 Yukon ratepayers if each project was to be developed will depend on subsequent financial
24 assessments during project feasibility and implementation stages of development.

25
26 No feasibility studies or ratepayer impact analysis were prepared for Drury Lake or Anvil
27 Creek, while Atlin Hydro ratepayer impact analysis are prepared for the EPA purposes.
28 The following is specifically noted regarding the three projects referenced in the question.

29
30 **Atlin Hydro Expansion**

31
32 Atlin Hydro Expansion was selected in the 10-Year Renewable Electricity Plan as a
33 potential near term option in the portfolio because of its ability to supply both dependable
34 capacity and firm energy, and because of its significantly shorter project development
35 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		
<u>Winter Energy Price (Jan-May, Sept-Dec)</u>	\$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	

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

1 this pre-feasibility assessment was estimated at \$0.21/kWh and levelized cost of capacity
2 at \$635/kW-year.

3
4 Experience with hydro projects demonstrates potential for material cost escalation as
5 assessments move through from pre-feasibility to feasibility studies, from studies to final
6 design and contracting, and from contracting to final commissioning. Drury Creek is a
7 greenfield site that was expected to require YEC to be the party developing the project.

8
9 YEC does not have detailed ratepayer impact analysis for the project as it requires
10 consideration of LTA thermal displacement rather than using project levelized cost of
11 energy based on total energy generated over the year.

12
13 **Anvil Creek**

14
15 The project was not included as part of shortlisted small hydro projects in the 10-Year
16 Renewable Electricity Plan.

17
18 A few run-of-river configurations were considered up and down Anvil Creek. The project
19 location has previously been associated with Anvil Lake, a site that does not offer the
20 same generating opportunities. The most attractive options for Anvil Creek assume long
21 tunnels, resulting in average to higher LCOE returns, as such the project was not
22 shortlisted. It was only possible to fully regulate the river for winter generation with a very
23 tall dam structure, which proved to be cost prohibitive (i.e., \$1 billion for 30 MW of firm
24 winter generation).

25
26 **(b)**

27
28 In general, subject to meeting all relevant regulations and terms, a renewable energy
29 hydro project located in Yukon, owned by parties other than the utilities, and supplying the
30 YIS under an EPA with YEC would fall under OIC 2019/25 with all energy delivered priced
31 on the basis of the applicable blend fuel thermal price last approved by the Board and
32 inflated each year thereafter at 50% of CPI.

33
34 **(c)**

35
36 Under OIC 2019/25 for the on-grid projects:
37

- 1 • The price paid by an electrical utility for a kWh of electricity under an on-grid
2 electricity purchase agreement is to be based on the utility's average blended fuel
3 price per kWh for thermal generation most recently approved by the board before
4 the date on which the agreement takes effect.
- 5
- 6 • This price is subject to annual escalation at 50% of the CPI increase.
- 7
- 8 • Provision is also made for compensation (section 5(1)) as well as for utility
9 recovery of costs (section 2).

10
11 In summary, OIC 2019/25 requires that for each kWh delivered the utility must pay the last
12 approved blended fuel cost regardless of the thermal displacement benefits of that
13 delivered energy.

14
15 In contrast, the Atlin Amended EPA energy prices have been set based on LTA thermal
16 displacement benefits. Atlin Amended EPA pricing also focuses on energy delivered
17 during the "winter" period [defined as Jan-May, Sep-Dec], while for SOP IPP projects the
18 utility pays the specified price for all annual generation.

19
20 The Atlin Amended EPA also includes a capacity payment price which is not included in
21 the OIC 2019/25.

22
23 Section 4.2 of YEC's Submission provides the following assessment of the difference
24 between this EPA and equivalent SOP IPP developments under OIC 2019/25:

25
26 "The Amended EPA effect on customer rates is materially lower than equivalent
27 SOP IPP renewable supplies. Total annual cost at 2024\$ prices for EPA deliveries
28 to YEC for LTA energy and dependable capacity equals \$6.4 million/year until the
29 end of 2034, and \$5.0 million/year thereafter.²

- 30 o In contrast, SOP IPP deliveries for renewable projects with the same
31 annual LTA energy delivery capability (41.5 GWh/year including

² The \$6.4 million/year (2024\$) until the end of 2034 (and the \$5 million thereafter) assumes 8.75 MW dependable capacity (\$1.75 million/year) plus 34.0 GWh/year winter delivered energy (\$4.6 million/year for years until the end of 2034 and \$3.3 million for years thereafter as per Appendix A, Table A3). The Project is capable of providing 7.5 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 7.5 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 \$0.7 million/year (price at 50% of the approved blended fuel cost).

- 1 summer period energy) and the same 2024\$ YEC blended fuel cost of
2 \$0.19/kWh would cost YEC \$7.9 million/yr. for energy only.
3
4 o Additional costs would also be needed with SOP IPP options in order
5 to provide the equivalent 8.75 MW of dependable capacity from another
6 new source. The least costly new source would likely be new thermal
7 generation with an LCOC (2024\$) of at least \$200/kW-year or \$1.75
8 million/year for 8.75 MW.”