

**JOHN MAISSAN
(JM)**

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

2

3 **REFERENCE:**

4

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

11

12 **QUESTION:**

13

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

16

17 **ANSWER:**

18

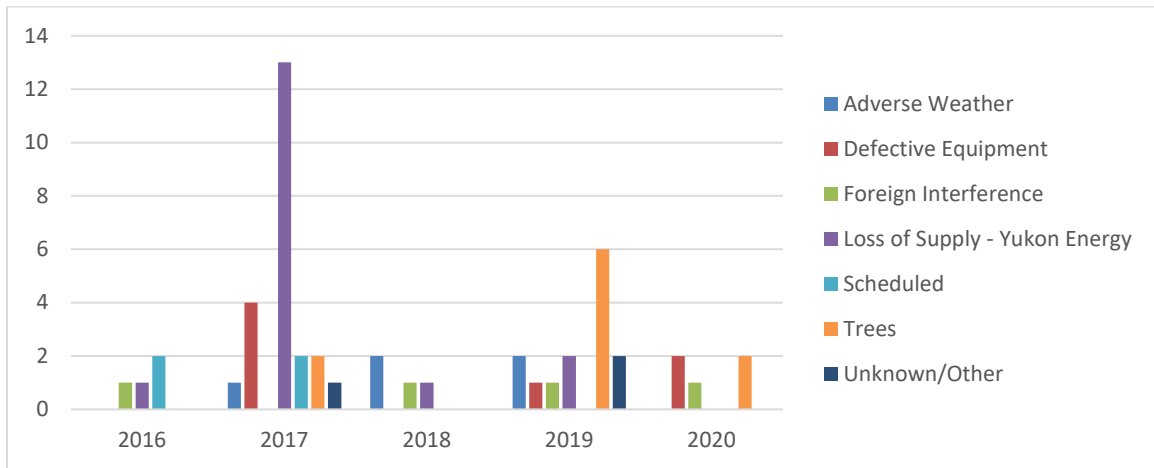
19 **(a)**

20

21

22

Outage statistics – AEY Line 6L11



23

24

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

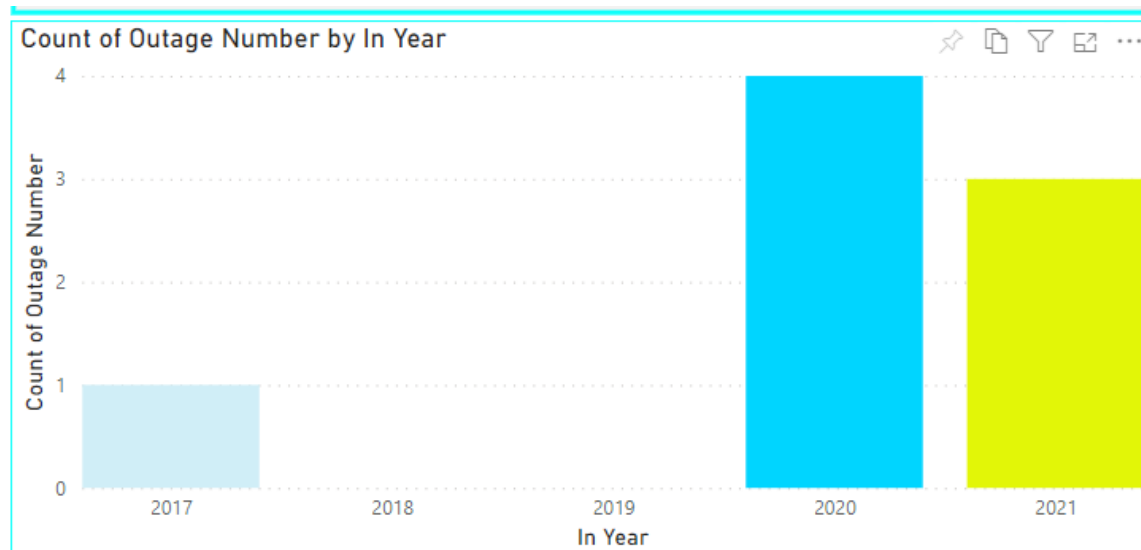
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L171 – Aishihik to Takhini



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L176/7 – Mayo to Dawson



5

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

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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

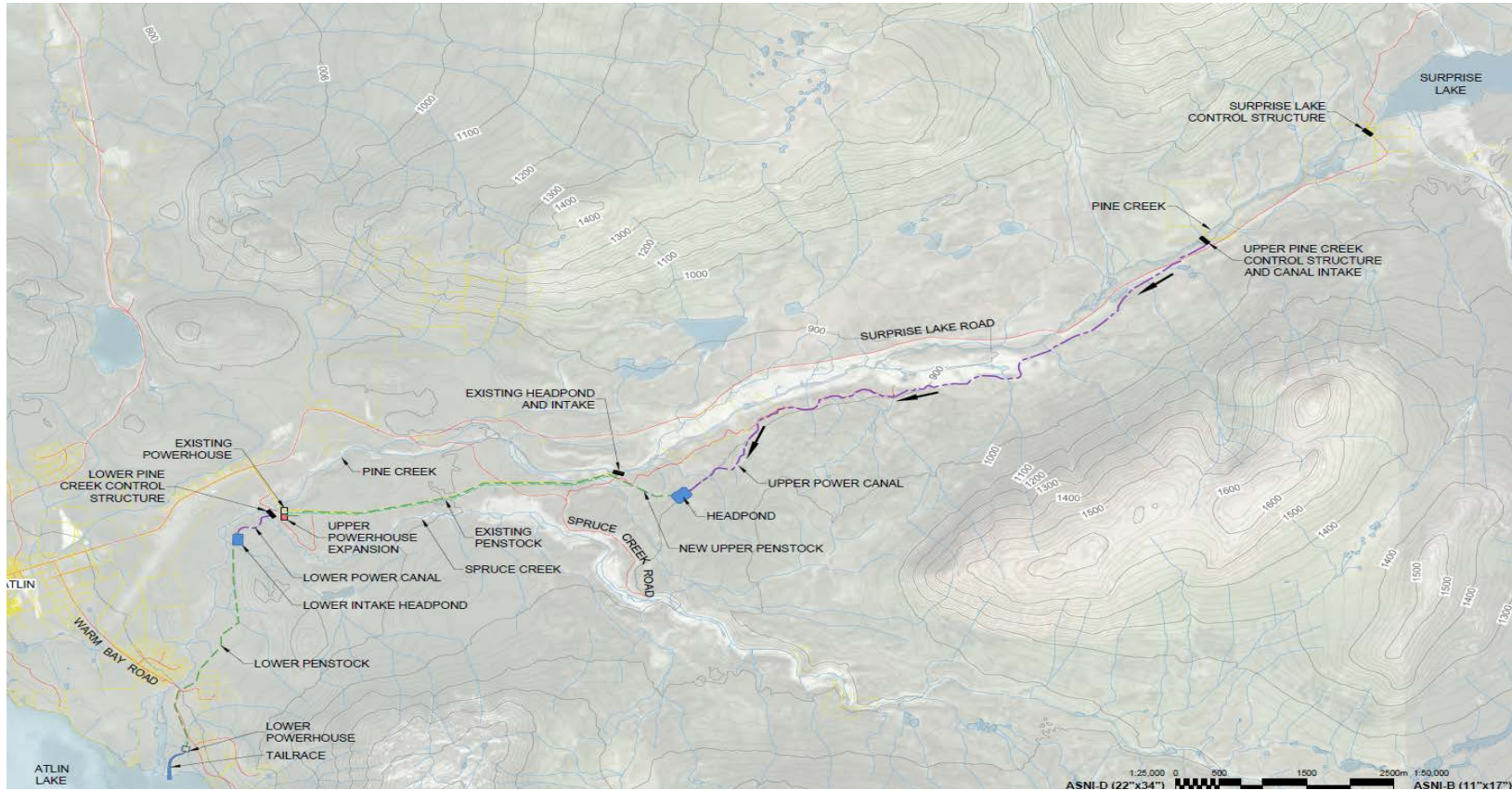
22 **(b)**

23

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

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3

Appendix 1 - Expanded Figure 2-1



4

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

2

3 **REFERENCE:**

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

8 **QUESTION:**

9

10 a) Please confirm that this is a 24-hour day, and explain what a day with minus 30°C
11 temperature at Whitehorse is – is it a day in which the temperature reached minus
12 30°C at any time in the day, or in which the mean or average daily temperature is
13 minus 30°C or lower, or in which the temperature stays below minus 30°C for the
14 entire day?

15

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

19

20 **ANSWER:**

21

22 **(a)**

23

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

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

28

1 **(b)**

2

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

6

- 7 • 1995 the temperature dropped below -30°C for December 4-9 (6 days);
8 • 2006 the temperature dropped below -30°C for November 24-28 (5 days);
9 • 2012 the temperature dropped below -30°C for November 29 (1 day); and
10 • 2016 the temperature dropped below -30°C for December 13-15 (3 days).

11

12 In each case the -30°C temperature lasted no more than six days.

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

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

29

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

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

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 Firm
6 Winter Energy Price of \$0.132/kWh for 2024-2034 [\$0.107/kWh for 2035 and
7 thereafter], and Non-Firm Winter Energy Price of \$0.072/kWh for 2024-2034 [\$0.
8 027/kWh for 2035 and thereafter] all in 2024\$ and increased by 50% of CPI for
9 each year. These firm and non-firm energy pricings are determined based on total
10 YEC load, including industrial load as reviewed in Tables A3-1 and A3-2 in
11 Appendix A [i.e., LTA thermal energy displacements are determined including
12 industrial load].

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

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3 **REFERENCE:**

4

5 **PREAMBLE: Page 5 top: “Expected Winter Period deliveries to YEC per**
6 **calendar year are 30.8 GWh LTA energy and 25.2 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

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

3

4 **ANSWER:**

5

6 **(a) through (c)**

7

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

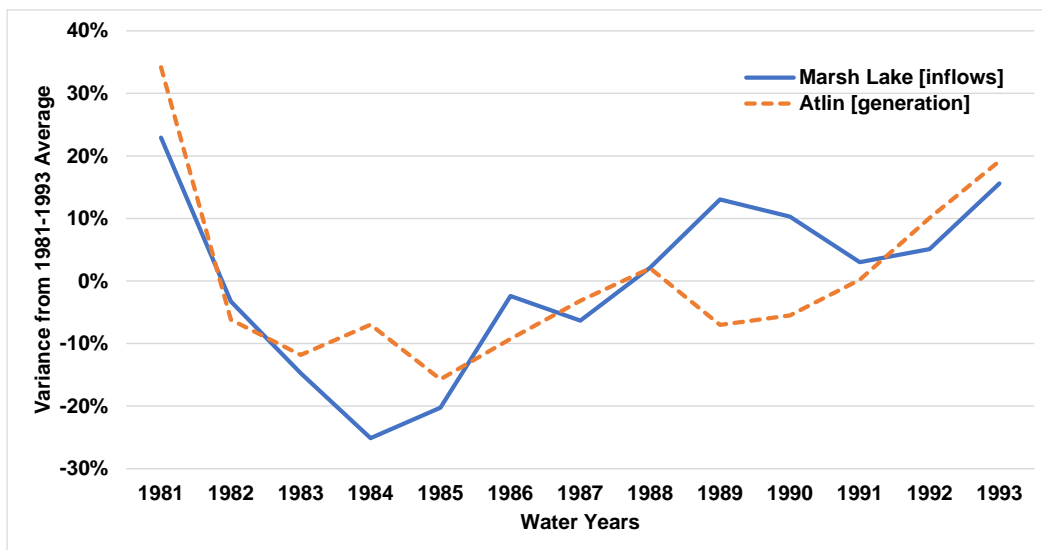
12

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

16

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

20



21

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

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

- 4
- 5 • The LTA thermal displacement benefits are determined using Atlin generation
6 based on long-term average water conditions [the average Atlin hydro generation
7 for all water records]; they were also separately determined using only low water
8 year generation deliveries that reflect the lowest Atlin hydro generation in water
9 year 1978.
- 10
- 11 • The EPA energy pricings were determined based on firm and non-firm energy
12 deliveries.
 - 13 ○ The firm energy pricing reflects estimated LTA thermal displacement based
14 on only the firm hydro generation that can be delivered by the Project
15 during low water conditions [i.e., the lowest annual hydro generation over
16 all 35 water years]. This is a factor which will tend to reduce impacts for
17 YEC from variances in LTA vs low water year energy deliveries.
 - 18 ○ The non-firm energy pricing determined based on only the added benefits
19 from LTA hydro in excess of generation in the lowest water year.
- 20
- 21 • The LTA thermal displacement benefits are based on 38 water years of hydro
22 availability for all Yukon Energy hydro generation storage facilities [i.e., takes into
23 account variation in seasonality and water availability of Whitehorse, Aishihik and
24 Mayo hydro generation storage facilities].
- 25
- 26 • The analysis utilizes LTA renewable generation through the year for assessing
27 impacts of new renewable generation, including SOP IPP generation and the Atlin
28 EPA.

29
30 **(d)**

31
32 Yes. The LTA thermal displacement benefits are determined using the YECSIM model
33 which uses weekly time steps (including LTA weekly time step assessments for all new
34 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.

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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

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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

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 4
 5
 6

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 **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 \$206 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 \$56 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.

1 **Appendix A**

2

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

3

4

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

7

8

1. Total capital cost assumed at \$206 million [2024\$].

9

2. Grant amount assumed at \$150 million [2024\$].

10

3. Fixed O&M at \$2.0 million/year [2024\$] – reflects approximately 1% of hydro plant capital cost plus provision for BC water rental charges with allowance for efficiencies due to existing hydro facilities plus an allowance for transmission O&M [THELP’s estimate for this cost is slightly lower to reflect internal efficiencies when operating with the Existing Plant].

11

12

13

14

4. Variable non-fuel O&M at \$5/MW [2024\$].

15

5. Dependable capacity at 8.5 MW.

16

6. Annual energy at 36.2 GWh and LTA thermal displacement benefits at 19.6 GWh.

17

18

7. Weighted Average Cost of Capital at 4.79% (YEC 2021 GRA WACC) and inflation at 2%.

19

8. The life of the project assumed at 40 years.

20

9. The LCOE and LCOC at 2024\$.

21

22

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

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

11

12 b) During the Peak Winter Period (PWP):

13 i. what will be the power flows toward Teslin from Jake's Corner and
14 towards Whitehorse?

15 ii. what will be the power flows towards Whitehorse from north of the North
16 M'Clintock road?

17 iii. what will be the power flows towards Whitehorse north of the Carcross
18 cut-off?

19 iv. what will be the power flows at the YEC S150 substation?

20

21 **ANSWER:**

22

23 **(a)**

24

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

27

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

29

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

33

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

36

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

10

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

16

17 iii. 4.78 MW out of Carcross Cut-off towards MacRae.
18 1.945 MW through MacRae towards Whitehorse S150

19

20 iv. From Jake's Corner: 1.90 MW
21 From P126 Whitehorse Diesel: 4.98 MW
22 From S171 Riverside (through Whitehorse S150 138 kV): 24.49 MW
23 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 19.6 GWh for
27 2024). Principle #3 then states that YEC purchases all available winter energy that THELP
28 provides (LTA deliveries of 30.8 GWh).

29

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

31

- 32 • LTA displacement in 2024 equals only approximately 63.5% of LTA deliveries.
- 33
- 34 • The average energy price paid of all energy delivered is then set at 63.5% 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. 30.8 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 requested information. Please also see response to JM-
31 YEC-1-16. For simplicity, full LTA deliveries assumed each calendar year (commissioning
32 in October is ignored) and capacity payments are recorded fully for each calendar year.

33

34 The following is noted regarding the table provided below:

- 1 • The EPA pricing assumes the mine load continues to 2034 and uses 2024 load
 2 forecast for 2024-2034 years. Therefore, the pricing and payments would be the
 3 same as for questions a) and c). Added Load sharing commences starting in 2035.
 4
- 5 • The CPI assumed at 2% for energy and capacity rate calculations.
 6
- 7 • Non-industrial winter load of 388 GWh forecast for 2035 is assumed to increase at
 8 0.12%/year after 2035.
 9
- 10 • The YUB price is assumed at \$0.19/kWh [2024\$] with inflation at 2%/year as
 11 stipulated in the question.
 12
- 13 • The rate for Added Load is calculated as per EPA provision. For example, in 2065
 14 the Added Load is 14.2 GWh and therefore the Added Load rate is \$0.023/kWh
 15 [$\$0.19 \times \text{inflation} = \$0.428 \times 11.7\% \times 14.2 / 30.8$]. This rate is applied to energy
 16 delivered (30.8 GWh assumed each year).
 17

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

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

Yukon Energy Corporation
JM-YEC-1-10

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh											
<i>Firm Winter Energy</i>	0.119	0.121	0.122	0.123	0.124	0.125	0.127	0.128	0.129	0.131	0.132
<i>Non-Firm Winter Energy</i>	0.030	0.030	0.031	0.031	0.031	0.032	0.032	0.032	0.033	0.033	0.033
Energy Payment, \$million	3.173	3.204	3.236	3.269	3.302	3.335	3.368	3.402	3.436	3.470	3.505
Added Winter Load, GWh		0.5	0.9	1.4	1.9	2.3	2.8	3.3	3.7	4.2	4.7
<i>Added Load Rate [YUB price \$0.19/kWh]</i>		0.000	0.001	0.001	0.002	0.002	0.003	0.003	0.004	0.005	0.005
<i>Added Load Rate Payment, \$m</i>		0.013	0.027	0.041	0.056	0.071	0.087	0.104	0.121	0.139	0.158
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	248.7	253.6	258.7	263.9	269.2	274.6	280.0	285.6	291.4	297.2	303.1
Dependable Capacity Payment, \$m	1.989	2.029	2.070	2.111	2.153	2.196	2.240	2.285	2.331	2.378	2.425
1 Total Payment, \$million	5.162	5.247	5.333	5.421	5.511	5.602	5.696	5.791	5.888	5.987	6.087
2											
	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	
Energy Price, \$/kWh											
<i>Firm Winter Energy</i>	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146	
<i>Non-Firm Winter Energy</i>	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037	
Energy Payment, \$million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871	
Added Winter Load, GWh	5.2	5.6	6.1	6.6	7.0	7.5	8.0	8.5	8.9	9.4	
<i>Added Load Rate [YUB price \$0.19/kWh]</i>	0.006	0.006	0.007	0.008	0.009	0.009	0.010	0.011	0.012	0.013	
<i>Added Load Rate Payment, \$m</i>	0.177	0.197	0.218	0.240	0.262	0.285	0.309	0.334	0.360	0.387	
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	
Dependable Capacity Payment \$/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5	
Dependable Capacity Payment, \$m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956	
3 Total Payment, \$million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214	

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

(b)

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

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

- The non-industrial growth is assumed at the same rate as in question a) [0.12%/year after 2035].
- The added annual industrial load is assumed at 60 GWh/year for 2035-2044 [assume 42.6 GWh “winter” load that affects the Additional Payment].

Yukon Utilities Board
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Yukon Energy Corporation
JM-YEC-1-10

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh											
<i>Firm Winter Energy</i>	0.132	0.133	0.135	0.136	0.137	0.139	0.140	0.142	0.143	0.144	0.146
<i>Non-Firm Winter Energy</i>	0.072	0.073	0.073	0.074	0.075	0.076	0.076	0.077	0.078	0.079	0.080
Energy Payment, \$million	3.725	3.762	3.800	3.838	3.876	3.915	3.954	3.993	4.033	4.074	4.114
Added Winter Load, GWh											
<i>Added Load Rate [YUB price \$0.19/kWh]</i>											
<i>Added Load Rate Payment, \$m</i>											
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	200	204.0	208.1	212.2	216.5	220.8	225.2	229.7	234.3	239.0	243.8
Dependable Capacity Payment, \$m	1.600	1.632	1.665	1.698	1.732	1.767	1.802	1.838	1.875	1.912	1.950
1 Total Payment, \$million	5.325	5.394	5.464	5.536	5.608	5.681	5.756	5.831	5.908	5.986	6.065
2											
	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh											
<i>Firm Winter Energy</i>	0.119	0.121	0.122	0.123	0.124	0.125	0.127	0.128	0.129	0.131	0.132
<i>Non-Firm Winter Energy</i>	0.030	0.030	0.031	0.031	0.031	0.032	0.032	0.032	0.033	0.033	0.033
Energy Payment, \$million	3.173	3.204	3.236	3.269	3.302	3.335	3.368	3.402	3.436	3.470	3.505
Added Winter Load, GWh		43.1	43.5	44.0	44.5	44.9	45.4	45.9	46.3	46.8	4.7
<i>Added Load Rate [YUB price \$0.19/kWh]</i>		0.039	0.041	0.042	0.043	0.045	0.046	0.047	0.049	0.050	0.005
<i>Added Load Rate Payment, \$m</i>		1.214	1.252	1.291	1.330	1.371	1.413	1.456	1.501	1.546	0.158
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	248.7	253.6	258.7	263.9	269.2	274.6	280.0	285.6	291.4	297.2	303.1
Dependable Capacity Payment, \$m	1.989	2.029	2.070	2.111	2.153	2.196	2.240	2.285	2.331	2.378	2.425
3 Total Payment, \$million	5.162	6.448	6.558	6.671	6.785	6.902	7.022	7.143	7.267	7.394	6.087

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Yukon Energy Corporation
JM-YEC-1-10

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh										
<i>Firm Winter Energy</i>	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146
<i>Non-Firm Winter Energy</i>	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037
Energy Payment, \$million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871
Added Winter Load, GWh	5.2	5.6	6.1	6.6	7.0	7.5	8.0	8.5	8.9	9.4
<i>Added Load Rate [YUB price \$0.19/kWh]</i>	0.006	0.006	0.007	0.008	0.009	0.009	0.010	0.011	0.012	0.013
<i>Added Load Rate Payment, \$m</i>	0.177	0.197	0.218	0.240	0.262	0.285	0.309	0.334	0.360	0.387
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5
Dependable Capacity Payment, \$m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956
1 Total Payment, \$million	6.190	6.295	6.402	6.512	6.623	6.737	6.852	6.971	7.091	7.214
2										
	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh										
<i>Firm Winter Energy</i>	0.147	0.149	0.150	0.152	0.153	0.155	0.156	0.158	0.159	0.161
<i>Non-Firm Winter Energy</i>	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040	0.040	0.041
Energy Payment, \$million	3.910	3.949	3.989	4.029	4.069	4.109	4.151	4.192	4.234	4.276
Added Winter Load, GWh	9.9	10.4	10.9	11.3	11.8	12.3	12.8	13.3	13.7	14.2
<i>Added Load Rate [YUB price \$0.19/kWh]</i>	0.013	0.014	0.015	0.016	0.017	0.018	0.020	0.021	0.022	0.023
<i>Added Load Rate Payment, \$m</i>	0.415	0.443	0.473	0.504	0.536	0.568	0.602	0.638	0.674	0.712
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	376.9	384.4	392.1	400.0	408.0	416.1	424.5	432.9	441.6	450.4
Dependable Capacity Payment, \$m	3.015	3.076	3.137	3.200	3.264	3.329	3.396	3.464	3.533	3.604
3 Total Payment, \$million	7.340	7.468	7.599	7.732	7.868	8.007	8.149	8.293	8.441	8.592
4										

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

- 1 **(d)**
- 2
- 3 The EPA energy pricing is not based on LCOE, but on LTA thermal displacement benefits.
- 4 Therefore, the requested information is not available.

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

2

3 **REFERENCE:**

4

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

8

9 **Page 14 Table 3-1**

10

11 **QUESTION:**

12

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

16

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

19

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

22

23 **ANSWER:**

24

25 **(a)**

26

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

29

30 50% of this 2021 GRA blended fuel price equals \$0.0918/kWh. This would be the summer
31 fuel price at times when the last approved YUB blend fuel price is \$0.1837/kWh.

32

33 **(b)**

34

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

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

5

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

12

13 **(c)**

14

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

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

2

3 **REFERENCE:**

4

5 **PREAMBLE: Page 17: “Winter vs Summer Shifts”, and**

6

7 **Page 21: “...The result is surplus renewable energy generation**
8 **during summer (which cannot be used or sold to other**
9 **jurisdictions) ...”**

10

11 **QUESTION:**

12

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

16

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

20

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

23

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

27

28 **ANSWER:**

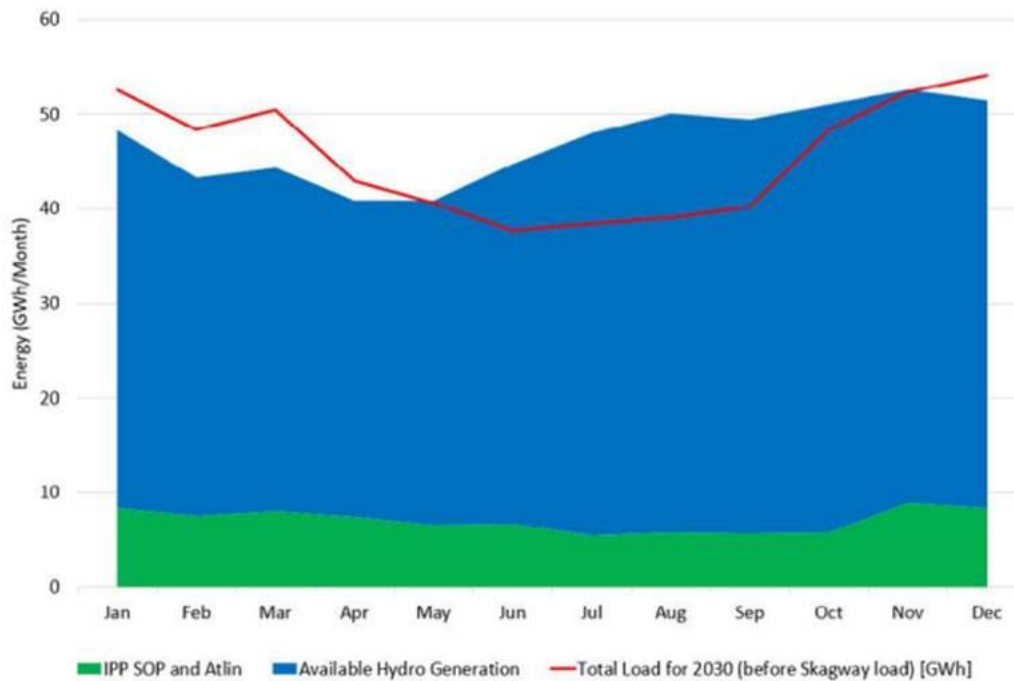
29

30 **(a)**

31

32 Yukon Energy does not have any surplus renewable energy in the winter months
33 (November through April). Surplus renewable energy is typically available June through
34 October. The figure below illustrates the expected renewable surplus on a monthly basis
35 (Figure 15 from the 10-year Renewable Electricity Plan – see YUB-YEC-1-32, Attachment
36 1).

Figure 15: Monthly Renewable Supply vs Demand (2030)



1

2

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

7

8 **(b)**

9

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

15

16 **(c)**

17

18 Please see the table below in 2021.

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

1

2 **(d)**

3

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

6

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

11

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

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

2

3 **REFERENCE:**

4

5 **PREAMBLE: Page 18 second paragraph: "... Without new resources, this**
6 **shortfall and the requirement for diesel rentals is forecast to**
7 **increase significantly in subsequent years due to peak load**
8 **growth and the retirement of existing resources.^{22, 23}"**

9

10 **QUESTION:**

11

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

14

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

16

17 **ANSWER:**

18

19 **(a)**

20

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

24

25 **(b)**

26

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

10

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

12

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

20

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

23

24 **ANSWER:**

25

26 **(a) and (b)**

27

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

31

32 **(c) and (d)**

33

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

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

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

2

3 **REFERENCE:**

4

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

9

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

12

13 **QUESTION:**

14

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

17

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

20

21 **ANSWER:**

22

23 **(a) and (b)**

24

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

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.

31

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.

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

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

Yukon Energy Corporation
JM-YEC-1-16

	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh										
<i>Firm Winter Energy</i>	0.133	0.135	0.136	0.137	0.139	0.140	0.141	0.143	0.144	0.146
<i>Non-Firm Winter Energy</i>	0.034	0.034	0.034	0.035	0.035	0.035	0.036	0.036	0.036	0.037
Energy Payment, \$million	3.540	3.575	3.611	3.647	3.683	3.720	3.757	3.795	3.833	3.871
Added Winter Load, GWh	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
<i>Added Load Rate [YUB price \$0.19/kWh]</i>	0.076	0.077	0.079	0.081	0.082	0.084	0.086	0.087	0.089	0.091
<i>Added Load Rate Payment, \$m</i>	2.337	2.384	2.431	2.480	2.530	2.580	2.632	2.684	2.738	2.793
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	309.2	315.4	321.7	328.1	334.7	341.4	348.2	355.2	362.3	369.5
Dependable Capacity Payment, \$m	2.474	2.523	2.573	2.625	2.677	2.731	2.786	2.841	2.898	2.956
1 Total Payment, \$million	8.350	8.482	8.616	8.752	8.891	9.031	9.175	9.321	9.469	9.620
2										
3										
	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065
Energy Delivered, GWh	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8	30.8
<i>Firm Winter Energy</i>	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2	25.2
<i>Non-Firm Winter Energy</i>	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Energy Price, \$/kWh										
<i>Firm Winter Energy</i>	0.147	0.149	0.150	0.152	0.153	0.155	0.156	0.158	0.159	0.161
<i>Non-Firm Winter Energy</i>	0.037	0.037	0.038	0.038	0.039	0.039	0.039	0.040	0.040	0.041
Energy Payment, \$million	3.910	3.949	3.989	4.029	4.069	4.109	4.151	4.192	4.234	4.276
Added Winter Load, GWh	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0	68.0
<i>Added Load Rate [YUB price \$0.19/kWh]</i>	0.093	0.094	0.096	0.098	0.100	0.102	0.104	0.106	0.109	0.111
<i>Added Load Rate Payment, \$m</i>	2.849	2.906	2.964	3.023	3.084	3.145	3.208	3.272	3.338	3.405
Dependable Capacity, MW	8	8	8	8	8	8	8	8	8	8
Dependable Capacity Payment \$/kW	376.9	384.4	392.1	400.0	408.0	416.1	424.5	432.9	441.6	450.4
Dependable Capacity Payment, \$m	3.015	3.076	3.137	3.200	3.264	3.329	3.396	3.464	3.533	3.604
4 Total Payment, \$million	9.774	9.930	10.090	10.251	10.416	10.584	10.754	10.928	11.105	11.284

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

2
3 **REFERENCE:**

4
5 **PREAMBLE: Page A-3 Table A3-1, and**

6
7 **Page 14, Table 3-1**

8
9 **QUESTION:**

10
11 a) In the 2024 load forecast portion of the table the non-industrial load is listed as
12 453.3 GWh, the industrial load as 74.6 GWh, and the total load at 527.9 GWh. The
13 YEC 2021 GRA forecast shows an industrial load of about 112.7 GWh (102.9 GWh
14 industrial sales + 9% load losses), non-industrial load of about 427.6 GWh (by
15 difference) and a total load of 538.7 GWh. Please explain the apparent
16 discrepancy between the 2024 forecast and 2021 actual numbers.

17
18 b) In the 2024 forecast YEC adds forecasted increased generation of 10.2 GWh for
19 hydro uprates and 39.9 GWh for “IPPs + incremental microgen”. Since
20 microgeneration is by definition behind the customers’ meters manifesting itself as
21 reduced load, how can such a number be determined or measured when it is a mix
22 of measured and non-measured supplies?

23
24 c) The non-industrial load is forecast to be 483.1 GWh per year in 2035 (Table A3-
25 5), please explain the calculation that resulted in a YIS Winter Period generation
26 of 388 GWh per year used in Table 3-1.

27
28 **ANSWER:**

29
30 **(a)**

31
32 YEC would like to clarify that the referenced 2021 GRA numbers are forecasts for 2021,
33 not actuals.

34
35 The load forecast for 2024 that was used for the EPA analysis is based on 10-Year
36 Renewable Plan that was developed in response to Yukon government’s draft Our Clean
37 Future: A Yukon strategy for climate change, energy and a green economy and reflects

1 ongoing economic growth of the Territory and increased demand for renewable energy
2 from the policies and actions outlined in the strategy, including increased demand for EVs.
3 The 10-Year Plan forecast included a 1.5%/year growth in non-industrial load between
4 2021 and 2024.

5

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

12

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

17

18 **(b)**

19

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

29

30 **(c)**

31

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

15

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

20

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

23

24 **ANSWER:**

25

26 **(a) and (b)**

27

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

33

34 **(c)**

35

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

13

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

16

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

19

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

22

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

25

26 **ANSWER:**

27

28 **(a) through (e)**

29

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

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

2

3 **REFERENCE:**

4

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

9

10 **QUESTION:**

11

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

14

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

17

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

20

21 **ANSWER:**

22

23 **(a)**

24

25 Confirmed.

26

27 **(b)**

28

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

31

32 **(c)**

33

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

10

11 b) Please provide the YEC upgrade costs.

12

13 **ANSWER:**

14

15 **(a) and (b)**

16

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

12

13 **ANSWER:**

14

15 **(a)**

16

17 Confirmed.

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

10

11 **ANSWER:**

12

13 **(a)**

14

15 Not confirmed. Please see response to CW-YEC-1-7 – the date for satisfaction of clause
16 2.1(d)(vii) has been extended to May 31, 2022.

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 March 31, 2022.

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

12

13 **ANSWER:**

14

15 **(a)**

16

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

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

2

3 **REFERENCE:**

4

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

6

7 **QUESTION:**

8

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

10

11 **ANSWER:**

12

13 **(a)**

14

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

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

20

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

23

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

26

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

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 MW to 8.5 MW or can it be
14 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 and
27 8.5 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 8,500 kW that is confirmed
35 at the final commercial operation date [COD] for Seller's Plant [therefore, the 8.5
36 MW is a cap, but this result during COD could be less than 8 MW], less

- 1
 - 2
 - 3
2. The reduction for a PWP as provided for in a Dependable Plant Capacity Test under Section 5.5 or Notice under Section 6.2 [these reductions could in principle reduce the DPCC to well below 8 MW, including to zero].

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 Correct.

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

16

17 The final sentence should read:

18

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

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

2

3 **REFERENCE:**

4

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

7

8 **QUESTION:**

9

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

11

12 **ANSWER:**

13

14 **(a)**

15

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

20

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

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 Attachment 1 to this response.

