

August 26, 2025

Ms. Lesley McCullough, Chair
Yukon Utilities Board
Box 31728, Whitehorse, YT Y1A 6L3

Dear Ms. McCullough:

Re: Yukon Energy's 2025-27 GRA – IR responses

Please see attached responses to Information Requests (IR) concerning Yukon Energy Corporation's (Yukon Energy or YEC) 2025-27 GRA. Yukon Energy is filing a consolidated package, including the pdf pages noted in the upper centre of the pages for ease of reference.

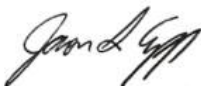
As indicated in the IR responses, Yukon Energy has noted some corrections to the Application that impact revenue requirement, including the amortization expense for Whitehorse and Mayo relicensing projects [YUB-YEC-1-50 (b)] and application of the deemed capitalization [UCG-YEC-1-8 (a) and (c)].

This Application was submitted earlier in the first test year than in previous filings, and it includes an additional forecast year (three years instead of two). The forecasts presented in the Application remain the primary basis for evaluation as they reflect the best available information at the time of filing. However, in responding to IRs, Yukon Energy has provided updated information on the following:

- Brushing cost [YUB-YEC-1-64 (a)];
- Insurance [YUB-YEC-1-47 (d)];
- Labour cost [YUB-YEC-1-37 (c)];
- Thermal consumables [YUB-YEC-1-37 (d)];
- Mobile diesel rental costs [YUB-YEC-1-37 (d)]; and
- The Whitehorse Power Expansion Project (now referred to as Whitehorse Power Centres Project) [YUB-YEC-1-8 (a) and (b)].

The updated information is not intended to constitute a revision to the Application but has been provided to support a more timely and efficient review and consideration by the Board.

Yours truly,



Jason Epp,
Vice President, Finance and CFO



YUKON ENERGY CORPORATION

2025-27 GENERAL RATE APPLICATION
ROUND 1 INTERROGATORY RESPONSES FILED

August 26, 2025

**NATHANIEL YEE
(NY)**

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Please provide an updated and complete YIS Generation Inventory that includes
6 the rentals. Format should be the same as "Appendix A: Existing Resources
7 Technical Attributes" on p. 71 of the 10 -Year Renewable Electricity Plan from
8 2020. Please provide separate tables for 2025-26, 2026-27 and 2027-28.
9

10 **ANSWER:**

11
12 **(a)**

13
14 Please see NY-YEC-1-1 Attachment 1 prepared based on the 2025-27 GRA assumptions,
15 including diesel rentals.

NY-YEC-1-1 Attachment 1

Location	Unit #	Prime Mover Type	Total Capacity (kW)	Max. Rated Winter Capacity (kW)	Dependable Capacity (kW)	Dependable Capacity (kW) - 2025/26	Dependable Capacity (kW) - 2026/27	Dependable Capacity (kW) - 2027/28
Aishihik								
Hydro	AH1	hydro	15,600	15,000	14,400	14,400	14,400	14,400
	AH2	hydro	15,600	15,000	14,400	14,400	14,400	14,400
	AH3	hydro	7,000	7,000	6,720	6,720	6,720	6,720
			38,200	37,000	35,520	35,520	35,520	35,520
Faro								
Diesel	FD7	diesel	3,000	3,000	2,970	2,970	2,970	2,970
	FD8	diesel	2,600	2,600	2,496	2,496	2,496	2,496
	FD9	diesel	2,600	2,600	2,496	2,496	2,496	2,496
			8,200	8,200	7,962	7,962	7,962	7,962
Dawson								
Diesel	DD1	diesel	800	800	768	768	768	768
	DD2	diesel	1,000	1,000	960	960	960	960
	DD3	diesel	1,030	1,030	989	989	989	989
	DD4	diesel	1,440	1,440	1,382	1,382	1,382	1,382
	DD5	diesel	1,500	1,500	1,440	1,440	1,440	1,440
	YM1	diesel	1,440	1,200	1,152	1,152	1,152	1,152
			7,210	6,970	6,691	6,691	6,691	6,691
Callison								
Diesel		diesel	3,250	3,250	3,120	3,120	3,120	3,120
		diesel	3,250	3,250	3,120	3,120	3,120	3,120
			6,500	6,500	6,240	6,240	6,240	6,240
Mayo								
Diesel	MD1	diesel	1,000	1,000	970	970	970	970
	MD2	diesel	1,000	1,000	970	970	970	970
	MD3	diesel	1,000	950	922	922	922	922
			3,000	2,950	2,862	2,862	2,862	2,862
Hydro	MH1	hydro	2,550	1,500	1,500	1,500	1,500	1,500
	MH2	hydro	2,550					
	MBH1	hydro	5,310	2,500	2,500	2,500	2,500	2,500
	MBH2	hydro	5,310	2,500	2,500	2,500	2,500	2,500
			15,720	6,500	6,500	6,500	6,500	6,500
Whitehorse								
Hydro	WH1	hydro	5,800	3,500	3,360	3,360	3,360	3,360
	WH2	hydro	5,800	4,138	3,972	3,972	3,972	3,972
	WH3	hydro	8,400					
	WH4	hydro	21,327	20,000	19,200	19,200	19,200	19,200
			41,327	27,638	26,532	26,532	26,532	26,532
Natural Gas	WG1	Natural Gas	4,400	4,400	3,872	3,872	3,872	3,872
	WG2	Natural Gas	4,400	4,400	3,872	3,872	3,872	3,872
	WG3	Natural Gas	4,400	4,400	3,872	3,872	3,872	3,872
			13,200	13,200	11,616	11,616	11,616	11,616
Diesel	WD4	diesel	2,500	2,500	2,475	2,475	2,475	2,475
	WD5	diesel	2,500	2,500	2,475	2,475	2,475	2,475
	WD6	diesel	2,500	2,500	2,475	2,475	2,475	2,475
	WD7	diesel	3,300	3,000	2,970	2,970	2,970	2,970
	WD8	diesel	2,600	2,600	2,496	2,496	2,496	2,496
	WD9	diesel	2,600	2,600	2,496	2,496	2,496	2,496
			16,000	15,700	15,387	15,387	15,387	15,387
BESS								
			5,500	5,500	5,500	5,500	5,500	5,500
AEY diesel								
	diesel		7,175	6,363	5,727	5,727	5,727	5,727
	Hydro		95,247	71,138	68,552	68,552	68,552	68,552
	Natural Gas		13,200	13,200	11,616	11,616	11,616	11,616
	Diesel		40,910	40,320	39,142	39,142	39,142	39,142
	Battery		5,500	5,500	5,500	0	5,500	5,500
	AEY diesel		7,175	6,363	5,727	5,727	5,727	5,727
	DSM		500	500	500	250	350	500
	Total		162,532	137,021	131,037	125,287	130,887	131,037
YEC Diesel Rentals								
	diesel		39,600	39,600	33,660	33,660	33,660	33,660

Note: At present, the diesel rentals are in the following locations: Whitehorse 10, Faro 7 and Mayo 5.

REFERENCE: 2025-27 YEC GRA Information Requests**QUESTION:**

- a) Please provide the stacking order for thermal generation – separate lists for 2025-26, 2026-27 and 2027-28.

ANSWER:**(a)**

The generation stacking order changes based on available information at the time of generation, including demand, available generation resources, resources required for system stability, air emissions permit and water use licence conditions under normal operating conditions, rental diesel generator contract provisions and other operational considerations at the time (e.g., fuel supply, availability of labour resources, etc.).

The following shows the approximate stacking order of thermal units for the upcoming 2025/26 winter based on information available at the time of preparation of the response. The stacking order for the 2026/27 winter will be revisited closer to the winter of 2026/27, and will be adjusted as considered necessary. Similarly, the stacking order for the 2027/28 winter will be revisited closer to the winter of 2027/28 and adjusted as needed.

Type/ Location	Units	Notes
YEC LNG	WG1, WG2 and WG3 (dependable capacity is provided in NY-YEC-1-Attachment 1)	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.
Whitehorse rentals	8 units (dependable capacity is provided in NY-YEC-1-Attachment 1), excluding two additional units	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Notes 1 and 2.
Faro rentals	7 units (dependable capacity is provided in NY-YEC-1-Attachment 1)	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Notes 1 and 2.
Mayo rentals	5 units (dependable capacity is provided in NY-YEC-1-Attachment 1)	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Notes 1 and 2.

Type/ Location	Units	Notes
YEC Whitehorse diesel	WD4, WD5, WD6, WD7, WD8, WD9 Dependable capacities are provided in NY-YEC-1-Attachment 1	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.
YEC Callison diesel	2 units (dependable capacity is provided in NY-YEC-1-Attachment 1)	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.
YEC Faro diesel	2 new units (dependable capacity is provided in NY-YEC-1-Attachment 1), FD7 (dependable capacity is provided in NY-YEC-1-Attachment 1)	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.
YEC Dawson diesel	DD1, DD2, DD3, DD4, DD5, YM1 Dependable capacities are provided in NY-YEC-1-Attachment 1	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.
YEC Mayo diesel	MD1, MD2, MD3 Dependable capacities are provided in NY-YEC-1-Attachment 1	The dependable capacity is provided in NY-YEC-1-Attachment 1. See Note 1.

Notes:

1. Under normal operating conditions, total thermal operation at each site will not exceed authorized limits under applicable air emissions permits: i.e. 42 MW for Whitehorse, including both diesel and LNG; 15.5 MW for Callison; 20.4 MW for Faro diesel (subject to approval of Yukon Energy's pending application for a permit amendment to increase Faro's current authorized limit of 15.5 MW); 7.1 MW for downtown Dawson diesel; 9 MW for Mayo Secondary Thermal¹; and 3 MW for downtown Mayo.
2. Where feasible, maintain each rental operational hours under 500 hours/28 days allowance as per contract.
3. The generation stacking order is subject to changes based on available information at the time of generation, including demand, available generation resources, resources required for system stability, air emissions permit and water use licence conditions under normal operating conditions, rental diesel generator contract provisions and other operational considerations at the time (e.g., fuel supply, availability of labour resources, etc.).

¹ Yukon Energy has noted a typographical error on PDF page 114 in Appendix 3.1 of the Application, where the applied-for increase in permitted thermal generating capacity at Mayo Secondary was described as being "from 4.8 MW to 9 MW". This should read as "from 4.9 MW to 9 MW". Note further that the applied-for amendment to the Mayo Secondary Air Emissions Permit was approved by the Yukon Government Department of Environment on July 24, 2025.

REFERENCE: 2025-27 YEC GRA Information Requests

QUESTION:

a) Please provide total costs of rental diesel by location.

ANSWER:

(a)

Please see the table below that shows the total rental cost, including transportation, commissioning/set-up, maintenance and stand-down fees, where applicable, for each test year [calendar year basis]. The rental costs exclude fuel costs.

\$millions	2025	2026	2027
Whitehorse	2.74	2.77	2.82
Faro	2.49	2.54	2.59
Mayo	1.76	1.79	1.83
Total	6.99	7.09	7.23

As noted in the Application [page 2-16, footnote #23], the 2025-27 GRA assumes 10 rental units in Whitehorse, 7 units in Faro and 5 units in Mayo.

For updated information on diesel rental costs for 2025, 2026 and 2027, please see YUB-YEC-1-37(d).

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Exit strategy for rental diesel: Is there a plan to phase out “temporary” rental diesel,
6 or will it continue to be used for the foreseeable future?

7
8 **ANSWER:**

9
10 **(a)**

11
12 Please see response to YUB-YEC-1-8 (a) and (b).

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) Are there any longer term plans to develop renewables >2 MW? If so, please list
6 and describe and provide proposed timelines.

7
8 **ANSWER:**

9
10 **(a)**

11
12 Yukon Energy's Integrated Resource Plan includes two key components:

- 13
14 1. A Short-Term Action Plan (STAP) that identifies the electricity needs of Yukoners
15 for the next 10 years and the generation resources needed near Whitehorse,
16 Yukon's largest and fastest growing load centre, to meet those needs. Please also
17 see the response to YUB-YEC-1-8 a) and b).
18
19 2. A System Resource Plan that includes completing a 20-year load forecast,
20 updating generation resource options, conducting desktop modeling to analyze the
21 ability of generation resources to meet the Yukon's electricity needs over the
22 timeline, and supporting Yukon Development Corporation with a Call for Power in
23 the next 12 to 24 months to develop distributed renewable energy resources
24 across the territory.
25

26 Actions identified in the STAP contributed to the development of two documents: *Building*
27 *a Resilient and Renewable Energy Future: Yukon Energy's Road Map to 2050* and
28 *Chapter 1: A Reliable and Robust Grid*.

29
30 The short-term actions identified between 2025 and 2030 focus on building a reliable and
31 robust grid to meet growing demands for power, provide the foundation for grid-
32 modernization technologies to support evolving customer needs, and safely integrate
33 more renewables onto the system. Increasing the reliability and stability of the grid is a
34 critical first step in ensuring that more sources of intermittent renewables can be integrated
35 on the electricity system without impacting grid stability and reliability.

- 1 It is through the Call for Power noted and Yukon Development Corporation's territory-wide
- 2 energy planning efforts as part of pre-feasibility work on the BC Interconnect that
- 3 opportunities for renewables greater than 2 megawatts may become available.

REFERENCE: 2025-27 YEC GRA Information Requests**ISSUE:** GHG Emissions**QUESTION:**

a) Please provide a table of total greenhouse gas emissions in kilotonnes by year from 2017 through what is expected in 2028, with assumptions clearly stated.

b) Please provide GHG emissions by location for each year, 2021-2028.

c) Please provide GHG emissions of LNG vs diesel emissions for installed and rental diesel.

ANSWER:**(a) and (c)**

Please see the table below for the annual total greenhouse gas emissions. Yukon Energy does not have forecast GHG emissions.

	2017	2018	2019	2020	2021	2022	2023	2024
GHG, kilotonnes	7.7	18.8	32.2	37.0	24.3	22.9	25.4	52.7

Emissions from diesel generation from the National Inventory Report (Environment Canada) average approximately 697.5 tonnes of CO₂e per GWh (or 0.0006975 g/kWh). Natural gas GHG emissions are approximately 451 tonnes of CO₂e per GWh (or 0.000451 g/kWh). Yukon Energy uses the same assumptions for rented diesel and owned diesel for the calculation of the GHGs.

(b)

Please see the table below for the annual total greenhouse gas emissions by location. Yukon Energy does not have forecast GHG emissions.

	2021	2022	2023	2024
GHG, kilotonnes				
Whitehorse	21.6	17.4	21.4	38.7
Faro	1.4	3.3	1.7	5.9
Dawson	1.2	2.0	2.2	4.7
Mayo	0.1	0.1	0.2	3.4
1 Total	24.3	22.9	25.5	52.7

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) How does YEC propose meeting the goals of Our Clean Future? From Our Clean
6 Future: “While aiming for an aspirational target of 97 per cent by 2030, develop
7 legislation by 2023 that will require at least 93 per cent of the electricity generated
8 on the Yukon Integrated System to come from renewable sources, calculated as
9 a long-term rolling average.”

10
11 **ANSWER:**

12
13 **(a)**

14
15 Please see the response to NY-YEC-1-5.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) In past GRAs, “temporary” rental diesel was presented as the only feasible option.
6 In the Atlin EPA proceeding, Atlin and Moon Lake were presented as the only
7 feasible options to avoid needing 35+ rental diesels, and now the only feasible
8 option is permanent diesel. Does YEC have plans or intentions to adopt a more
9 comprehensive long-term planning approach, so that future proceedings can
10 present genuine alternatives for discussion, rather than focusing solely on the
11 short-term, “only feasible” options – as has happened since 2021?

12
13 **ANSWER:**

14
15 **(a)**

16
17 GRA filings are, of necessity, focused on the prudence of resources selected for the GRA
18 test years, including capital assets that are feasible to bring into service during those
19 years. However, evidence is provided in each application and in response to IRs on current
20 longer term resource planning that assesses what is feasible for future years.

21
22 For the current Application, please see the response to YUB-YEC-1-8 (a) and (b) for
23 review of current thermal generation resource planning for at least the next decade, and
24 the response to NY-YEC-1-5 for review of current broader resource planning activities.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) From PDF p. 23: "There is a great deal at stake. The financial cost of getting this
6 wrong is too great. A decision made today needs to hold up 20, 30 and even 40
7 years from now." Please explain what decisions YEC has gotten right and wrong
8 in the last 20 years? The last 10 years? The last 5 years?
9

10 **ANSWER:**

11
12 **(a)**

13
14 When read in the context of the general rate application, the statement noted in the
15 question from a recent publication by Electricity Canada speaks to growing demands for
16 electricity across Canada and the need to build new electricity projects to meet that
17 demand, and to expand and modernize the electricity system to ensure that growing
18 communities continue to be connected to sources of power.
19

20 Yukon Energy's resource planning and GRA's for the last decade have consistently noted
21 the surging demand for peak non-industrial power, how the growth of this load has
22 continued to accelerate, and the challenges and options available to address the resulting
23 winter dependable capacity requirements. Please see response to YUB-YEC-1-8 for
24 review of the related decisions and actions to address this challenge during this period.
25

26 Under the *Public Utilities Act (PUA)* Yukon Energy has statutory obligations to provide
27 service to customers. Generally speaking, decisions that Yukon Energy makes to increase
28 the supply of electricity to Yukoners to meet forecast loads, to reduce demands for power
29 where this is feasible, to maintain and upgrade current generation sources and
30 transmission and distribution systems it owns, and to improve service to customers are
31 the right decisions. So are decisions that recognize that Yukon Energy cannot complete
32 these projects on its own, but rather in partnership with First Nation and other
33 governments, and industry.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) PDF p. 24 mentions moving some diesels that are in the north closer to
6 Whitehorse. What are the specifics of this?

7
8 **ANSWER:**

9
10 **(a)**

11
12 Yukon Energy's Short-Term Action Plan (STAP), Chapter 1: A Reliable and Robust Grid
13 2025-2030, includes actions to ensure that Yukon Energy has an adequate and balanced
14 supply of winter power in both the North Yukon and South Yukon regions to meet regional
15 demands for power. Right now, about 75% of the electricity used on the main grid is in the
16 Whitehorse area.

17
18 One of the actions noted in the STAP was the proposed construction of the Whitehorse
19 Power Centres in the Whitehorse area. This project includes installing diesel, LNG or dual-
20 fuel resources in the centres as well as adding critical pieces of infrastructure (e.g.,
21 substation) to the grid to meet growing demands for power and make the electricity system
22 more resilient. The other action noted was to move some of the thermal resources that
23 exist in North Yukon region closer to Whitehorse.

24
25 The specific timing of when thermal resources in North Yukon would be moved to South
26 Yukon, the amount that would be moved and where they would be moved from is unknown
27 at this time and would depend on multiple factors including but not limited to the pace of
28 load growth in both the North and South Yukon regions and the specific timing of when
29 the Whitehorse Power Centre sites are constructed.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) The GRA mentions increasing grid strength and adding thermal resources in the
6 short term to support future renewables. What renewable projects will be
7 supported? Anything specific projects >2MW in development?

8
9 **ANSWER:**

10
11 **(a)**

12
13 Please see the response to NY-YEC-1-5.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Is there a timeline of when DSM might provide significant benefit?

6
7 **ANSWER:**

8
9 **(a)**

10
11 YEC currently has a target of 7 MW of dependable capacity from its DSM programs by
12 2030. As noted in response to UCG-YEC-1-11, Yukon Energy is currently conducting cost-
13 effectiveness evaluations.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) What is the status and future of TOU metering?

6
7 **ANSWER:**

8
9 **(a)**

10
11 There are no specific proposals in the Application regarding Time of Use (TOU) rate
12 options. Yukon Energy and ATCO Electric Yukon are working to implement infrastructure
13 that would allow implementation of rate design options. For example, please see section
14 5.1B-3.3 in Tab 5 (pdf page 335) for the details of the Grid Modernization Program –
15 Advanced Metering Infrastructure (AMI) project, which would increase flexibility in rate
16 design, including TOU rate options.

17
18 Yukon Energy believes that TOU can be effective, especially to reduce the peak demand,
19 however, more work is needed to understand how it could be implemented here in the
20 Yukon. We would also need to understand how TOU could be implemented with
21 consideration to avoid discrimination against specific customer groups, such as lower
22 income households, considering that electricity is an essential service.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Is DSM expected to be a significant contributor to addressing peak loads? What
6 are the future goals and timelines for DSM?

7
8 **ANSWER:**

9
10 **(a)**

11
12 Please see the response to NY-YEC-1-12.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **ISSUE:** Renewable energy targets

4
5 **QUESTION:**

6
7 a) Does Yukon Energy have specific renewable energy targets (by % of generation
8 or MW capacity) for 2030, 2035, or 2050?.

9
10 b) Please describe how YEC is planning to meet these targets.

11
12 **ANSWER:**

13
14 **(a)**

15
16 Yukon Energy's vision for 2050 is to support a thriving, healthy and prosperous Yukon. It's
17 a place where a resilient electricity system fuels Yukoners' homes, businesses and lives,
18 supports economic opportunities, strengthens Arctic security, and advances meaningful
19 reconciliation with First Nations. It's a lower-carbon future envisioned by the governments
20 of Canada and the Yukon.

21
22 Yukon government's climate change strategy, *Our Clean Future*, outlines an aspirational
23 target of 97 per cent renewable electricity generation by 2030, and a goal to develop
24 legislation that will require at least 93 per cent of the electricity generated on the Yukon
25 Integrated System to come from renewable sources, calculated as a long-term rolling
26 average.

27
28 Yukon Energy does not have specific renewable energy targets beyond those outlined by
29 the Yukon government but is supporting Yukon Development Corporation to develop the
30 next resource plan with its related renewable energy plans and targets.

31
32 **(b)**

33
34 Please see the response to NY-YEC-1-5.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) Typically it has been difficult for customers to make sense of the ever changing
6 riders on billing statements. What would be the advantages of providing actual
7 rates on billing statements – the fixed charge and cost per kWh?

8
9 **ANSWER:**

10
11 **(a)**

12
13 The Board recently considered the issue of bill simplification in the rate rebasing
14 proceeding, including submissions from Mr. Yee, and directed ATCO Electric Yukon and
15 Yukon Energy to implement bill changes in Board Order 2023-08. ATCO Electric Yukon
16 and Yukon Energy followed the Board's direction in this regard, and the changes directed
17 in Order 2023-08 were made effective in December of 2024. Therefore, Yukon Energy is
18 not planning to revisit the billing statement changes.

19
20 Although this matter is outside of the scope of this proceeding, Yukon Energy, to be
21 helpful, is working with ATCO Electric Yukon (AEY) to illustrate the rates in Rate
22 Schedules with YEC Rider J and AEY Rider R included. An example of the preliminary
23 format is attached (see NY-YEC-1-16 Attachment 1). It should be noted that the rates in
24 the brackets are for illustrative purposes only and could be subject to rounding. The
25 provided format could also be modified as this issue is being worked on by the utilities.



Page 2 of 2
Effective: 2011 07 01
Supercedes: 1997 01 01

RATE SCHEDULE - 1160
RESIDENTIAL SERVICE
HYDRO, NON-GOVERNMENT

AVAILABLE:

In Carcross, Carmacks, Champagne, Dawson, Elsa, Faro, Haines Junction, Johnson's Crossing, Keno, Marsh Lake, Mayo, Pelly Crossing, Stewart Crossing, Ross River, Tagish, Teslin and Whitehorse.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial, industrial or government use.

RATE:

Charges for service in any one billing month shall be the sum of the following:

(a)	<u>Customer Charge</u>	\$14.65	[\$27.50 with YEC Rider J and AEY Rider R included]
(b)	<u>Energy Charge</u>		
	For the first 1,000 kW.h	12.14¢/kW.h	[22.79¢ with YEC Rider J and AEY Rider R included]
	Between 1,001 - 2,500 kW.h	12.82¢/kW.h	[24.06¢ with YEC Rider J and AEY Rider R included]
	For energy in excess 2,500 kW.h	13.99¢/kW.h	[26.25¢ with YEC Rider J and AEY Rider R included]

MINIMUM MONTHLY BILL:

The minimum monthly charge is the customer charge of \$14.65.

[\$27.50 with YEC Rider J and AEY Rider R included]

RATE MODIFICATIONS APPLICABLE:

For multiple residence service on one meter, see Rider A; for fuel adjustment Rider, see Rider F.

TERMS AND CONDITIONS OF SERVICE:

The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Please explain why YEC does not disclose the total cost per kWh, inclusive of all
6 riders on customer bills.

7
8 **ANSWER:**

9
10 **(a)**

11
12 Please see the response to NY-YEC-1-16.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Would YEC support publishing an annual summary of the actual rate per kWh for
6 each customer class, inclusive of all riders? Why or why not?

7
8 **ANSWER:**

9
10 **(a)**

11
12 Please see the response to NY-YEC-1-16.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) Has YEC conducted any public engagement or consultation on the issue of billing
6 statements and understanding rates and showing actual rates?

7
8 **ANSWER:**

9
10 **(a)**

11
12 The Board recently considered the issue of bill simplification in the limited scope
13 proceeding, including submissions from Mr. Yee, and directed the Utilities (Yukon Energy
14 and ATCO Electric Yukon) to implement bill changes in Board Order 2023-08. The Utilities
15 followed the Board's direction in this regard, and the changes directed in Order 2023-08
16 were made effective in December of 2024. Yukon Energy shared information with its
17 customers about the new format via social media (posted on community Facebook groups
18 and on Yukon Energy's main Facebook page), its office in Dawson, its website and
19 through conversations with customers who made inquiries by phone, email or in-person.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) How will YEC inform customers of each rate increase?

6
7 **ANSWER:**

8
9 Yukon Energy updates the 'rates' page on its website¹, issues a news release on its
10 website and sends it to local media outlets, conducts interviews with interested media
11 outlets when requested and posts to its Facebook page as well as in Facebook groups of
12 the communities that receive bills from Yukon Energy. Yukon Energy also provides key
13 messages and answers to Frequently Asked Questions to both Yukon Energy and ATCO
14 Electric Yukon customer service staff to use in their conversations with customers about
15 their electricity bills.

16
17 Yukon Energy also follows direction it receives from the Yukon Utilities Board, which in
18 2025 included:

- 19
20 • Placing ads in the local newspapers and on local radio channels;
21 • Hosting a public workshop; and
22 • Sending an email to stakeholders and intervenors with a plain language summary
23 of the rate increase and invitation to the public workshop.

24
25 Moving forward, Yukon Energy will continue to use these methods to inform customers of
26 each rate increase.

¹ <https://yukonenergy.ca/customer-service/rates/>

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) Please provide Yukon Energy's legal and regulatory justification for any planned
6 operation of rental diesels that may exceed permitted capacity.
7

8 **ANSWER:**

9
10 **(a)**

11
12 As noted in Appendix 3.1 of the current 2025-2027 Application (PDF page 114,
13 footnote 4), Yukon Energy previously addressed this question (in the context of the Yukon
14 Utilities Board's regulatory mandate under the *Public Utilities Act*) in the rebuttal evidence
15 it provided on February 8, 2024 in the 2023/24 GRA (Exhibit 9). See also Yukon Energy's
16 March 22, 2024 Final Argument (Section 4.3, pages 63-64) and its April 2, 2024 Reply
17 Argument (Section 2.2.3, pages 18-23) from the 2023/24 GRA.
18

19 The question of whether the Board erred in law or exceeded its jurisdiction under the
20 *Public Utilities Act* by approving rates that allow Yukon Energy to recover costs attributable
21 to rental diesel units exceeding permitted capacity is currently before the Yukon Court of
22 Appeal, in Mr. Yee's appeal from the 2023/24 GRA Decision (Board Order 2024-05) on
23 that issue (Court of Appeal File No. 24-YU922). A copy of the factum filed by Yukon Energy
24 in that appeal on June 20, 2025 is attached (NY-YEC-1-21, Attachment 1). The appeal is
25 currently scheduled to be heard by a division of the Court of Appeal on November 20,
26 2025.

Court of Appeal File No. 24-YU922

COURT OF APPEAL

ON APPEAL FROM an Order of the Yukon Utilities Board, dated July 12, 2024 (Board Order 2024-05)

BETWEEN:

Nathaniel Yee

AND:

Yukon Energy Corporation and Yukon Utilities Board

Respondents

COURT OF APPEAL
Cour d'appel
FILED / DÉPOSÉ

JUN 20 2025

Appellant
For Yukon
pour le Yukon

RESPONDENT'S FACTUM OF YUKON ENERGY CORPORATION

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INDEX

CHRONOLOGY	I
OPENING STATEMENT	III
PART 1 STATEMENT OF FACTS.....	1
PART 2 ISSUE ON APPEAL.....	8
PART 3 ARGUMENT	9
PART 4 NATURE OF ORDER SOUGHT	25
APPENDICES	26
LIST OF AUTHORITIES	37

CHRONOLOGY

September 27-29, 2021	The Respondent, Yukon Utilities Board (" Board ") conducts a public hearing under the <i>Public Utilities Act</i> , R.S.Y. 2002, c. 186 (" PUA ") respecting the 2021 General Rate Application (" 2021 GRA ") of the Respondent, Yukon Energy Corporation (" YEC ").
March 16, 2022	The Board issues its final decision on the 2021 GRA in Board Order 2022-03, approving YEC's revenue requirement for 2021. Amongst other things, the decision approves YEC's recovery of costs for diesel rental units, including costs attributable to capacity exceeding the amounts authorized by YEC's then-existing air emission permits (the " Air Emissions Permits ") under the <i>Environment Act</i> , R.S.Y. 2002, c. 76 [Environment Act] and <i>Air Emissions Regulations</i> , OIC 1998/207 [Air Emissions Regulations]. As determined by the Board, that additional capacity was required to enable YEC to respond to an emergency event. The Board approved those costs after hearing, considering and rejecting argument from the Appellant, Mr. Yee, opposing their inclusion in YEC's revenue requirement.
December 19 and 20, 2022	Emergency event due to high system/customer demand during extreme cold winter weather conditions, requiring YEC to exceed its permitted diesel generation capacity in Whitehorse for a total of approximately 25 hours to ensure uninterrupted service to customers and avoid a significant and immediate risk of harm to the public. YEC promptly notifies Environment Yukon of this exceedance.
August 31, 2023	YEC files its 2023-2024 General Rate Application (" 2023-2024 GRA ") with the Board. Amongst other things, YEC seeks recovery of costs associated with 20 diesel rental units in Whitehorse, Faro and Mayo with a combined total dependable generating capacity of 36 MW. This included 17.95 MW in excess of the capacity then authorized by YEC's Air Emissions Permits, which continued to be required to enable YEC to respond to an emergency event.
January 31 and February 2, 2024	Emergency event due to an unplanned outage at YEC's Aishihik Hydroelectric Generating Station, requiring YEC to exceed its permitted diesel generation capacity in Whitehorse for five hours on January 31, 2024 and a further ten minute period on February 2, 2024 to ensure uninterrupted service to customers and avoid a significant and immediate risk of harm to the public. YEC again notifies Environment Yukon of this exceedance.

ii

March 4-7, 2024	The Board conducts a public hearing under the <i>PUA</i> respecting YEC's 2023-2024 GRA.
July 12, 2024	The Board issues its final decision on the 2023-2024 GRA in Board Order 2024-05 (the " Decision "), with supporting Reasons for Decision in Appendix A. Amongst other things, the Decision again approves YEC's recovery of costs for diesel rental units, including costs attributable to capacity exceeding the amounts authorized by the Air Emissions Permits that was required to enable YEC to respond to an emergency event.
July 26, 2024	The Board issues Errata providing its corrected Reasons for Decision in Board Order 2024-05. (The corrections are not relevant to the issue raised by this appeal.)
August 9, 2024	Mr. Yee applies to the Yukon Court of Appeal for leave to appeal Board Order 2024-05 under section 69 of the <i>PUA</i> (naming only YEC as a respondent).
November 8, 2024	Bennett J.A. orders that the Board be added as a respondent to Mr. Yee's leave to appeal application under Rule 2(2) of the <i>Yukon Court of Appeal Rules, 2005</i> (<i>Yee v. Yukon Energy Corporation</i> , 2024 YKCA 13).
February 6, 2025	Griffin J.A. grants Mr. Yee's application for leave to appeal (<i>Yee v. Yukon Energy Corporation</i> , 2025 YKCA 3).

OPENING STATEMENT

The appellant defines success on this appeal as “encourag[ing] YEC’s compliance with YESAA and the *Environment Act*.”¹ But neither of those Acts is the subject of this appeal; nor is the Board tasked with interpreting, applying or enforcing their provisions.

The Board’s mandate under the *Public Utilities Act* and its regulations, including the *Rate Policy Directive (1995)*, is to exercise its broad discretion to approve just and reasonable electricity rates that are sufficient to enable YEC to recover its estimated reasonable operating costs, plus a fair return (less 0.5%) on its equity used to finance its rate base, while ensuring safe and reliable electricity service in the Yukon.

In the 2023-2024 GRA giving rise to the Decision under appeal, YEC explained, and the Board accepted, that YEC’s operating costs included costs associated with diesel rental units whose total generation capacity exceeded the normal operating thresholds authorized by YEC’s Air Emissions Permits, but which are nevertheless needed to ensure that YEC has sufficient reliable capacity to respond to emergency events that present a significant and immediate risk to public welfare, health and safety.

Evidence before the Board demonstrated that this emergency capacity was in fact relied on briefly by YEC on two recent occasions, in order to fulfil its statutory obligations to provide service to customers under the *PUA*. In both instances, YEC reported the exceedances to the appropriate regulator, Environment Yukon, thereby enabling Environment Yukon to determine what if any regulatory response was appropriate under the *Environment Act*, having regard to the relevant circumstances.

The Board made no error of law or jurisdiction by including the diesel rental costs in YEC’s revenue requirement. The Board’s decision to approve those costs involved the reasonable and lawful exercise of its broad rate-setting discretion under the *PUA*, supported by the jurisprudence and the Board’s own prior 2021 GRA decision. Mr. Yee’s appeal should be dismissed.

¹ Factum of the Appellant, filed May 12, 2025, Opening Statement (“**NY Factum**”); *Yukon Environmental and Socio-economic Assessment Act*, SC 2003, c. 7 [YESAA].

PART 1

STATEMENT OF FACTS

1. YEC is a government owned public electrical utility. It generates the majority of power in the Yukon on a hydro-based grid known as the Yukon Integrated System (“YIS”). YEC must, however, rely on thermal generation when customer loads exceed available hydro generation, particularly in the cold winter months, and to maintain a sufficient reliable supply of electricity that can be used in emergency conditions to provide uninterrupted service to customers and thereby avoid a significant and immediate risk of harm to the public.
2. YEC’s reliance on thermal generation to supplement and provide backup to its hydroelectric generation assets is especially important because of the isolated nature of the YIS, which is not interconnected to other jurisdictions. As such, YEC cannot import electricity from other jurisdictions when it is needed (nor can it export power when there is a surplus).² This requires the Yukon to be entirely self-reliant for a reliable supply of the electricity that is needed to serve Yukoners’ needs, including their need for heat during extreme cold conditions. Without a reliable supply of electricity in the winter, the risk to public harm is severe and immediate.
3. The present appeal arises out of YEC’s 2023-2024 GRA before the Board.
4. During 2023 and 2024, YEC’s thermal generation capacity included 20 diesel rental units (excluding two spares) across three locations (Whitehorse, Faro and Mayo) with a combined total dependable generating capacity of 36 MW.³
5. YEC holds Air Emissions Permits from Environment Yukon for the operation of its diesel rental units under the *Environment Act* and *Air Emissions Regulations*. At the time of the 2023-2024 GRA hearing, the permits authorized YEC to use its diesel generation facilities, including both rental diesel units and permanently

² Ex. 1, YEC 2023-2024 General Rate Application, Introduction to Application, p. 4, Joint Appeal Book of the Respondents YEC and the Board [RJAB] Tab 1, p. 5.

³ Ex. 4, NY-YEC-1-2 REVISED, January 4, 2024 [Exhibit 4], Attachment 1 at p. 2, RJAB Tab 4, p. 24.

installed units, to generate up to a combined total of 16.15 MW of power in Whitehorse, 15.5 in MW in Faro and 4.9 MW in Mayo.⁴ Those permitted capacities are less than the total diesel capacity that YEC maintains at those three sites for emergency purposes, which (as of the hearing) included a total of 17.95 MW in excess of the capacity authorized by YEC's permits: 10.55 MW in Whitehorse, 5.1 MW in Faro, and 2.3 MW in Mayo.⁵

6. In its 2023-2024 GRA application, YEC indicated (amongst other things) that, under the single contingency (N-1) capacity planning criterion,⁶ without rental diesels, there would be a capacity shortfall on the YIS of 35.3 MW for 2023 and 35.99 MW for 2024. It was YEC's evidence that it required at least 20 rental diesel units to close that capacity shortfall during the 2023 and 2024 test years – and to thereby ensure YEC's ability to provide uninterrupted electricity service to Yukoners during an emergency event.⁷
7. On July 12, 2024, the Board issued the Decision and its supporting Reasons for Decision, with errata reflected in a corrected version of its Reasons for Decision in issued on July 26, 2024 (collectively, the "**2024 Reasons**").⁸ In the Decision and

⁴ Ex. 5, YUB-YEC-1-35 REVISED, January 17, 2022 [**Exhibit 5**] Follow-up Question #3 and Attachment 3 (Permit No. 60-010-01), Attachment 6 (Permit No. 60-010-04) and Attachment 7 (Permit No. 60-010-05), RJAB Tab 5, pp. 45, 85, 101 and 106; Ex. 9, YEC Rebuttal Evidence, February 8, 2024 [**Exhibit 9**] p. 8, RJAB Tab 6, p. 123.

⁵ YEC Reply Argument, April 2, 2024 at p. 21 [**YEC Reply**], Appeal Record, Tab 1, p. 82 [**AR**]. These figures exclude two spare diesel rental units whose costs were excluded from YEC's revenue requirement.

⁶ The single contingency (N-1) capacity criterion is a planning standard that determines overall system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. It ensures that sufficient grid generation is available to meet firm residential and commercial customers' loads (excluding industrial loads) when a failure occurs to the single largest system component: Ex. 1, YEC 2023-2024 General Rate Application [**Exhibit 1**], Section 2.4, p. 2-13, AR Tab 1, p. 24.

⁷ Exhibit 1, Section 2.1, p. 2-4, AR Tab 1, p. 15. As noted further in its application, YEC was renting a total of 22 diesel rental units in 2023 and 2024 to close the capacity shortfall, including two spare units. However, YEC did not seek recovery of costs associated with the two spare units.

⁸ Board Order 2024-05, July 12, 2024 [**Decision**], AR Tab 2, p. 85; Appendix A Errata Reasons for Decision, July 26, 2024 [**2024 Reasons**], AR Tab 2, p. 87. (The corrections made in the "Errata" are not relevant to the issue raised on this appeal.)

the 2024 Reasons, the Board approved the inclusion of YEC's diesel rental costs in YEC's revenue requirement, as part of the Board's rate-setting mandate under Part 2 of the *PUA* and the *Rate Policy Directive (1995)*, OIC 1995/090 (as amended) (the "**Rate Policy Directive**").⁹

8. The approved costs for YEC's diesel rental units included both capacity falling within YEC's Air Emissions Permits, relied on by YEC for normal operations, as well additional capacity in excess of permitted capacity that – as the Board previously accepted in its 2021 GRA decision – is required to enable YEC to ensure an uninterrupted supply of electricity to customers under emergency conditions, consistent with YEC's statutory obligation to provide service under section 106 of the *PUA*.¹⁰
9. More particularly, the Board found previously in its 2021 GRA decision that an "N-1 dependable capacity shortfall event"¹¹ would on its face give rise to an emergency situation as contemplated by section 49(1) of the *Yukon Environmental and Socio-economic Assessment Act* ("**YESAA**"), in which it "is in the interest of public welfare, health or safety" for YEC to be able to respond. Having regard to the Board's own mandate "to ensure just and reasonable rates, as well as ensuring safe and reliable electricity service in Yukon", the Board was satisfied that it was necessary for YEC to maintain additional diesel capacity for that purpose.¹²
10. As an intervenor before the Board on the 2023-2024 GRA, Mr. Yee again took issue with the inclusion of the unpermitted portion of YEC's diesel rental capacity in its revenue requirement. His evidence filed with the Board largely consisted of argument, including various unsubstantiated allegations of fraud against YEC.¹³ In

⁹ 2024 Reasons at para. 138, AR Tab 2, p. 121.

¹⁰ YUB Board Order 2022-03, Reasons for Decision March 16, 2022 at paras. 107-108 [2022 Reasons], RJAB Tab 8, p. 159.

¹¹ See footnote 6 above.

¹² 2022 Reasons, at para. 110, RJAB Tab 8, pp. 159-160.

¹³ In its 2023-2024 GRA Costs Awards, the Board significantly reduced the costs granted to Mr. Yee for his participation in the 2023-2024 GRA, noting that "Mr. Yee did not act responsibly by bringing forward unsubstantiated allegations of fraud in the GRA

his final argument before the Board, however, Mr. Yee did not pursue his fraud allegations. Instead, his argument maintained that YEC should not be permitted to recover costs for diesel rental capacity exceeding its permitted capacity.¹⁴

11. Mr. Yee previously made similar arguments before the Board on YEC's 2021 GRA. In that proceeding, the Board dealt directly with Mr. Yee's arguments in issuing Board Order 2022-03 and its supporting Reasons for Decision, dated March 16, 2022 (the "**2022 Reasons**") (as noted above and addressed further below).¹⁵
12. On the 2023-2024 GRA, the Board considered Mr. Yee's position alongside the evidence submitted by YEC in approving all of YEC's sought diesel rental costs.¹⁶
13. In support of its request in the 2023-2024 GRA for the Board to allow recovery of its diesel rental costs, YEC presented evidence to the Board regarding the business case for diesel rental units, as well as evidence specifically addressing the need to maintain diesel rental capacity exceeding the amounts authorized by YEC's Air Emissions Permits to ensure YEC's ability to respond to an emergency.¹⁷
14. With respect to the continuing need for YEC to maintain diesel rental capacity in excess of its Air Emissions Permits to ensure its ability to provide uninterrupted

proceeding" and that his conduct "unnecessarily lengthened the duration of the hearing and resulted in unnecessary costs to YEC and other parties": Board Order 2025-11 YEC 2023-24 Costs Awards, May 21, 2025, at para. 34, RJAB Tab 9, p. 229.

¹⁴ Written Submission: Final Argument of Nathaniel Yee, March 22, 2024, AR Tab 1, p. 53.

¹⁵ 2022 Reasons at paras. 107-108, RJAB Tab 8, p. 159.

¹⁶ 2024 Reasons, at paras. 137-138, AR Tab 2, pp. 120-121.

¹⁷ Exhibit 1, Appendix 3.1, AR Tab 1, pp. 30-36; Ex. 2, YEC 2023-24 GRA Consolidated IR Responses, November 29, 2023, NY-YEC-1-12, NY-YEC-1-17 and NY-YEC-1-18, RJAB Tab 2, pp. 10-18; Ex. 3A, YEC Response to Notice of Motion Attachment 1, NY-YEC-1-12(a), RJAB Tab 3, p. 19; Exhibit 4, NY-YEC-1-2 REVISED, RJAB Tab 4, pp. 20-24; Exhibit 5, YUB-YEC-1-35 REVISED, RJAB Tab 5, pp. 25-61; Exhibit 9, RJAB Tab 6, pp. 115-124; Ex. 10, YEC 2023-24 GRA, YEC Opening Statement, March 4, 2024, pp. 4-5 RJAB Tab 7, pp. 129-130; Written Submission, YEC Final Argument, March 22, 2024, pp. 17-22, 63-64, AR Tab 1, pp. 67-75; YEC Reply Argument, pp. 18-23, AR Tab 1, pp. 78-84.

service to customers under emergency conditions, YEC also presented evidence to the Board about two recent occasions when that additional diesel rental capacity was both required and, in fact, used to respond to emergency events:

- (a) On December 19 and 20, 2022, at a time when YEC was facing very high system and customer demand, the Yukon experienced extreme low temperatures ranging around -40°C to -50°C. As a result, YEC was required to exceed its permitted diesel generation capacity in Whitehorse for a total of approximately 25 hours in order to meet demand and ensure uninterrupted service to customers and avoid a significant and immediate risk of harm. In accordance with its obligations under its Air Emission Permit, YEC promptly advised Environment Yukon of this exceedance, and ultimately Environment Yukon did not require YEC to take any further action in the circumstances.¹⁸
- (b) On January 31, 2024, YEC's Aishihik Hydroelectric Generating Station experienced a plant outage. That outage briefly required YEC to exceed its permitted diesel generation capacity in Whitehorse in order to meet demand and ensure uninterrupted service to customers while YEC staff worked to safely bring other resources online focusing on maintaining grid stability, resulting in YEC having to operate all available diesel rental units at the Whitehorse site for a short period of time. YEC exceeded its Whitehorse diesel rental unit permit for five hours on January 31, 2024 and a further ten minute period on February 2, 2024.¹⁹ Again, YEC reported this air emissions exceedance to Environment Yukon.²⁰

15. These incidents demonstrate that not only was it reasonable and prudent for YEC to maintain diesel rental unit capacity in excess of its Air Emissions Permits to

¹⁸ Exhibit 5, Follow-up Question #3 at pp. 21-22 and Attachment 8, RJAB Tab 5, pp. 45-46, 112-114.

¹⁹ Ex. 9, YEC Rebuttal Evidence to Nathaniel Yee Intervenor Evidence, February 8, 2024, at pp. 3-4 [Exhibit 9], RJAB Tab 6, pp. 118-119.

²⁰ Exhibit 9 at p. 7, RJAB Tab 6, p. 122.

ensure its ability to respond to emergencies, but that YEC has, in fact, had to use that excess diesel capacity for that purpose, to guard against the significant and immediate risk to public welfare, health and safety that would result from an electricity outage during the extreme cold winter weather conditions that exist in the Yukon. As YEC emphasized in its evidence before the Board, it is critically important for YEC to have sufficient diesel capacity installed to guard against that risk.²¹

16. It was also YEC's evidence before the Board that, regardless of YEC's views about Environment Yukon's legal authority to amend an existing Air Emissions Permit to authorize YEC's response to an emergency described in section 49(1) of YESAA, YEC was in the process of working with Environment Yukon, at its request, to expand its permits to cover its additional emergency capacity:²²

... Environment Yukon has informed YEC of its objective to bring YEC's emergency operation of its diesel units within its permitted capacity, so that YESAB may complete an environmental and socio-economic assessment of the potential impact of the emergency operations that will be authorized directly in YEC's permits, notwithstanding the exemption for emergency operations in s. 49 of YESAA. YEC is in the process of working with Environment Yukon to achieve this objective. In the meantime, however, YEC has accurately and transparently described in this GRA (and to Environment Yukon) how it would, in fact, operate its diesel units under its existing air emissions permits in the event of an emergency situation that requires it to temporarily exceed its permitted diesel capacity in order to prevent immediate harm to public welfare, health or safety.

17. It was YEC's undisputed evidence at the 2023-2024 GRA hearing that it would use – and has in fact used – its rental diesel units exceeding the capacity authorized by its Air Emissions Permits to the extent it may become necessary to do so in the event of an emergency, to prevent immediate harm to public welfare, health or safety, and that it would report any resulting exceedance to Environment Yukon in

²¹ Exhibit 5 at p. 21, RJAB Tab 5, p. 45.

²² Exhibit 9 at p. 5, footnotes omitted, RJAB Tab 6, p. 120.

accordance with section 113 of the *Environment Act* and the “unauthorized emissions” provisions of its permits.²³

18. YEC also provided the following further evidence about its communications with Environment Yukon about the practical need to exceed its permitted capacity in an emergency, in light of the harm that would result from a failure to do so:²⁴

In addition to YEC’s specific communications with Environment Yukon about the December 2022 and January 2024 occurrences, YEC has had other more general discussions with Environment Yukon about the extraordinary circumstance of exceeding its permitted capacity in an emergency. Based on those communications, it is YEC’s understanding that, notwithstanding the Regulatory Reminder, Environment Yukon fully recognizes that the harm that would result if YEC did not temporarily exceed its permitted capacity when necessary to respond to an emergency situation would be much greater than whatever impact might result from the pollutant emissions themselves.

19. The Board considered all of this evidence in the context of recognizing YEC’s description of the “special seasonal and multi-year conditions that vary with YIS load”, including winter constraints, created by “the predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory.” As noted in the Decision, “systems that are predominantly hydro-based are vulnerable to low-water conditions (drought) and require supplemental thermal generation.”²⁵
20. Ultimately, the Board accepted the evidence that a capacity shortfall exists on the YIS unless additional capacity is added, and that the diesel rental units were required to address that capacity shortfall during the 2023 and 2024 test years. Accordingly, the Board approved the inclusion of the diesel rental costs sought by YEC in YEC’s revenue requirement under the *PUA*.²⁶

²³ Exhibit 5 at pp. 20-21, RJAB Tab 5, pp. 44-45; Exhibit 9 at pp. 3-4 and 8, RJAB Tab 6, pp. 118-119 and 123.

²⁴ Exhibit 9 at p. 7, RJAB Tab 6, p. 122.

²⁵ 2024 Reasons at para. 68, AR Tab 2, p. 106.

²⁶ 2024 Reasons at para. 138, AR Tab 2, p. 121.

PART 2**ISSUE ON APPEAL**

21. The issue on appeal is whether the Board erred in law or exceeded its jurisdiction under the *PUA* by approving rates that allow YEC to recover costs attributable to rental diesel units that exceeded the capacity authorized by YEC's then-existing Air Emissions Permits.

PART 3

ARGUMENT

Standard of Review

22. Properly framed, the issue raised by Mr. Yee's appeal involves a straightforward exercise of the Board's broad discretion to approve operating costs for inclusion in YEC's revenue requirement, in the course of the Board's performance of its statutory duty to approve just and reasonable electricity rates under Part 2 of the *PUA* and its regulations, including the *Rate Policy Directive*.
23. Although Justice Griffin granted leave to appeal on the basis of a "narrow issue of law or the Board's jurisdiction" identified by Mr. Yee,²⁷ her decision leaves it open to the division of the Court hearing the appeal to determine the true nature of the issue raised, which YEC contends involves a question of mixed fact and law:²⁸

[38] [T]he position advanced by Mr. Yee is more akin to a case where the Board took into account a factor that it ought not to have: namely, YEC's forecast of costs that were premised on YEC exceeding its environmental permits.

...

[40] At the same time, I recognize that YEC has a viable argument that the Board simply exercised its discretion to set rates after fully considering this factor, leaving it to Environment Yukon to regulate environmental matters.

24. When the Board considers costs for inclusion in YEC's revenue requirement for the purpose of approving rates, it engages in a fact-driven, discretionary exercise.²⁹
25. Under section 69 of the *PUA*, leave to appeal to this Court is available only on questions of law or excess of jurisdiction. The *PUA* provides for no avenue of

²⁷ *Yee v. Yukon Energy Corporation*, 2025 YKCA 3 at para. 42 [**Yee v. YEC 2025**].

²⁸ *Yee v. YEC 2025* at paras. 38 and 40, emphasis added.

²⁹ See, e.g., *Altagas Utilities Inc. v. Alberta Utilities Commission*, 2020 ABCA 375 at paras. 21-22 [**Altagas**].

appeal for questions of fact or mixed fact and law. Thus, if the Court concludes that the question on appeal is a question of mixed fact and law, the Court has no jurisdiction to hear the appeal and grant the relief sought by Mr. Yee.³⁰

26. If, however, the Court finds that this appeal involves an extricable question of law or jurisdiction, YEC agrees that the standard of review is correctness, but not for the reasons set out by Mr. Yee.³¹ As this is a statutory appeal, not judicial review, extricable questions of law or jurisdiction are reviewable on the appellate correctness standard.³²
27. Even if the issues framed on this appeal present an extricable question of law or jurisdiction, this appeal does not raise a question of jurisdictional boundaries between two or more administrative tribunals of the nature described in *Vavilov*,³³ and the appeal should not be viewed through that lens.
28. Successful challenges to administrative decisions on the basis of the jurisdictional boundaries exception identified in *Vavilov* are rare.³⁴ They arise where one administrative body has interpreted the scope of its authority in a manner that is incompatible with the jurisdiction of another administrative body, such that there is a resulting “true operational conflict between two administrative bodies, pulling a party in two different and incompatible directions.”³⁵ It does not arise in situations where, as here, two administrative bodies are separately carrying out their mandates under separate legislative schemes, each regulating different aspects of a party’s operations.

³⁰ *Utilities Consumers’ Group v. Yukon Utilities Board*, 2001 YKCA 5 at para. 22, aff’d 2002 YKCA 8.

³¹ NY Factum at para. 14.

³² *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65 at paras. 34, 36-37 [**Vavilov**]; *Housen v. Nikolaisen*, 2002 SCC 33 at para. 8.

³³ *Vavilov* at paras. 63-64.

³⁴ *1193652 B.C. Ltd. v. New Westminster (City)*, 2021 BCCA 176 at para. 49 [**1193652 B.C. Ltd.**].

³⁵ *1193652 B.C. Ltd.* at para. 49, citing *Vavilov* at para. 64.

11

29. A “true operational conflict” only exists when the same party is required to do inconsistent things, such that “compliance with both is impossible.”³⁶
30. In the present case the Board was clear and careful in the Decision and the 2024 Reasons not to entrench upon the regulatory purview of Environment Yukon. The Decision does not give rise to a true operational conflict between the Board and Environment Yukon. The Decision involves a straightforward exercise of the Board’s broad discretion to review costs and set rates under the *PUA*, while making no conclusions about YEC’s compliance with the *Environment Act* or the *Air Emissions Regulations*.
31. There is nothing incompatible about the Board regulating YEC’s recoverable costs and setting rates while Environment Yukon regulates YEC’s air emissions. Questions of compliance with – and enforcement of – the *Environment Act* and its regulations are outside the Board’s regulatory mandate and properly left to Environment Yukon. That is precisely the divide that the Legislature intended.
32. There is certainly no true operational conflict arising from the Board’s Decision. Any obligations that YEC may have under the *Environment Act* and its regulations are completely independent of – and unaffected by – the Board’s determination of electricity rates under the *PUA*.

Overview: The Board Did Not Err by Considering Costs Attributable to Unpermitted Capacity

33. The *PUA* gives the Board a broad discretion to review costs for inclusion in YEC’s revenue requirement. That broad discretion is central to the rate-setting process, and falls squarely within the Board’s specialized expertise as regulator under the Act. It is constrained only by the terms of the Board’s legislative authority (including

³⁶ *Liberal Party of Canada v. The Complainants*, 2024 BCSC 814, at paras. 127-128.

the *PUA* and *Rate Policy Directive*), the jurisprudence, and the Board's prior decisions.³⁷

34. Nothing in the *PUA*, the jurisprudence, or the Board's prior decisions prevents the Board from considering costs attributable to generation assets that exceed YEC's current permitted capacity, if YEC can demonstrate that those assets are nevertheless both used and useful. Rather, the three elements noted above affirm that it is a central requirement of the Board's mandate to uphold the regulatory compact underlying the *PUA* by allowing YEC to recover its prudently incurred expenses.
35. In particular, there is no provision of the *PUA* or its regulations that imposes any legal restriction on the Board's authority to approve the inclusion of costs in YEC's revenue requirement that are reasonably incurred to meet YEC's duty to provide reliable electricity service to customers, regardless of the current permitting status of facilities to which those costs are attributable. This reflects an appropriate division of authority as between the Board and Environment Yukon as separate and distinct specialized administrative decision makers with different mandates and responsibilities.
36. The jurisprudence shows that rather than being constrained as to which costs the Board may consider when approving a utility's revenue requirement and setting rates, the Board, like all rate-setting regulators, is afforded a broad discretion.
37. The Decision under appeal also accords with the Board's previous decision on YEC's 2021 GRA, which addressed the same issues that Mr. Yee is raising now on this appeal. The Board explained in its 2022 Reasons that it does not have jurisdiction over YEC's licence approvals associated with its diesel generating units, and it allowed the diesel rental costs that were at issue in the 2021 GRA,

³⁷ *Yukon Energy Corporation v. Yukon Utilities Board*, 2017 YKCA 15 at para. 6 [**YEC v. YUB 2017**].

even to the extent they were attributable to the unpermitted portion of YEC's diesel generation capacity maintained for emergency purposes.

Statutory Scheme for Board's Rate-Setting Authority

38. The *PUA* establishes the Board as the specialized regulatory body responsible for reviewing and approving the rates of public utilities in the Yukon, including YEC.
39. The Board's statutory duty to approve YEC's rates is governed by Part 2 of the *PUA* and the *Rate Policy Directive*. Section 27 of the *PUA* sets out the Board's authority to set rates, while section 29 sets out a list of non-exhaustive factors that the Board may consider in setting rates.
40. Rates set by the Board are based on the Board's determination of "the revenue requirement for YEC to provide safe and reliable electric service at rates that are in the public interest."³⁸ Under the *Rate Policy Directive* and established jurisprudence, the Board is legally required to ensure that YEC's approved revenue requirement is sufficient to allow YEC to recover its estimated reasonable operating costs for the applicable test year(s), plus a fair return (less 0.5%) on its equity used to finance its rate base, in accordance with established Canadian rate-setting principles for utilities.³⁹
41. Costs approved for inclusion in YEC's revenue requirement must be "just and reasonable to both the utility and consumers", but beyond that overarching requirement, "nothing in the OIC [i.e. the *Rate Policy Directive*] or the *Act* constrains the Board's discretion to determine the methodology it uses to assess [YEC]'s costs in its rate-setting decisions."⁴⁰

³⁸ Decision at para. 137, AR p. 120.

³⁹ *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 at para. 65 [**ATCO**]; *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 at para. 16 [**Ontario (Energy Board)**]; *YEC v. YUB 2017* at para. 17; *Public Utilities Act*, R.S.Y. 2002, c. 186 ss. 29, 32; *Rate Policy Directive* (1995), ss. 2, 3, 4, 6, 7.

⁴⁰ *YEC v. YUB 2017* at para. 18.

14

42. This statutory scheme recognizes the regulatory compact that lies at the heart of energy production in Canada.⁴¹

62 Rate regulation serves several aims – sustainability, equity and efficiency – which underlie the reasoning as to how rates are fixed:

... the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future.... Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive “too low” a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be “too high”.

63 These goals have resulted in an economic and social arrangement dubbed the “regulatory compact”, which ensures that all customers have access to the utility at a fair price – nothing more. ... Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated. ...

64 Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer and the investor.

The Board Has No Regulatory Responsibilities Outside of the *PUA*

43. Mr. Yee has not pointed to any provision of the *PUA* or its regulations that the Board has purportedly failed to comply with or misinterpreted.
44. Specifically, Mr. Yee has not pointed to any provision of the *PUA* that could prohibit the Board from considering costs associated with unpermitted capacity, if and when the Board concludes (as it did in this case) that those costs were nevertheless reasonably incurred for the purpose of meeting YEC’s duty to provide

⁴¹ *ATCO* at paras. 62-64, internal citations omitted. See also *YEC v. YUB 2017* at paras. 5-7.

reliable electricity service to customers. This is because no such prohibition exists in the Act.

45. There is nothing in the *PUA* that prevents the Board from considering or including expenses associated with unpermitted capacity in its assessment of costs and rates. Similarly, there is nothing in the *PUA* that requires the Board to consider or assess the permitted or unpermitted status of costs. Rather, the permitted or unpermitted nature of YEC's activities is merely one of many factual considerations that the Board may take into account and weigh when considering what costs it will allow YEC to include in its revenue requirement, as part of the Board's exercise of its broad rate-setting discretion. The only relevant legal constraint on the Board is its obligation to allow YEC to recover its estimated reasonable operating costs.
46. This makes perfect sense, as the regulatory scheme of the *PUA* does not seek to duplicate or substitute for the regulatory responsibilities of other specialized administrative decision makers. Nor should it.
47. If the Court were to accept Mr. Yee's argument that the Board is obliged to consider the permitted or unpermitted nature of costs advanced by YEC for inclusion in its revenue requirement, there is no principled reason to limit this obligation only to permits issued under the *Air Emissions Regulations*. The Board would be similarly obliged to consider permits and licences from all regulatory authorities, from those issued by the Water Board under the *Waters Act* and *Waters Regulation* for its hydro facilities, right down to the licensing and insurance requirements under the *Motor Vehicles Act* for YEC's service vehicles.
48. Put another way, if this Court were to accept Mr. Yee's argument that the Board has no jurisdiction to include costs associated with unpermitted activities in its assessment of just and reasonable rates, this would fundamentally change the Board's responsibilities and mandate in rate setting. The Board would be tasked with assessing the permitted status of all costs sought to be recovered by YEC in its revenue requirement. This would be unduly burdensome for the Board, and

would not be in line with the Legislature's intended scope of the Board's authority and mandate.

The Legislature's Intention in Separate Regulatory Spheres

49. Not only would it be unduly burdensome to broaden the Board's mandate to require it to assess the permitted or unpermitted status of costs under different regulatory regimes, but such an exercise would also encroach inappropriately on the regulatory purview of other specialized administrative decision makers.
50. This cannot be what the legislature intended under the *PUA*. The Board has no specialized expertise in matters falling under the *Environment Act* or the *Air Emissions Regulations*, and there is nothing in the *PUA* to suggest that the Board should insert itself into matters assigned to Environment Yukon's jurisdiction.
51. It is simply not the Board's role to determine YEC's compliance – or any consequences of non-compliance – with requirements of the *Environment Act* and its regulations. Those are matters within the regulatory purview of Environment Yukon as the agency responsible for administering and enforcing the air emissions permitting scheme under the *Environment Act* and its regulations.
52. In its rebuttal evidence before the Board, YEC provided evidence that in the event of an emergency requiring YEC to exceed the limits of its air emissions permits, that exceedance would be reported to, and dealt with by, Environment Yukon:⁴²

[I]n the event of an emergency situation that requires YEC to exceed the permitted capacity of its diesel generation units to prevent immediate harm to public welfare, health or safety, YEC would temporarily exceed its permitted capacity as required (at its Whitehorse or other diesel plants) to respond immediately to the emergency. **YEC would then report that exceedance to Environment Yukon, as required by its air emissions permits and s. 113 of the *Environment Act*, and Environment Yukon would have the responsibility as regulator to determine what if any consequences should result.**

⁴² Exhibit 9 at p. 6, underlining in original, bold emphasis added, RJAB Tab 6, p. 121.

53. In earlier evidence, YEC also asserted that further assessment under *YESAA* was not required to operate rental diesel units in emergency situations, pursuant to section 49(1) of *YESAA*. YEC explained:⁴³

In the YIS context, if YEC were to experience a unplanned system outage or temporary failure under circumstances in which it does not have sufficient licensed diesel capacity to address the resulting shortfall in meeting customer demand – a very rare occurrence that likely could only arise during a winter cold weather period – that event would not constitute “normal operations” and would constitute an emergency event covered by subsection 49(1) of *YESAA*. This issue was explained in detail in the 2021 GRA.

54. Mr. Yee takes issue with YEC’s submissions regarding section 49(1) of *YESAA*, saying that even if the assessment step can be bypassed under section 49, that would not provide authorization for YEC to operate above its permitted capacity, quoting from a Department of Environment statement on the issue.⁴⁴ However, Mr. Yee’s reliance on the Environment Yukon statement underscores the fundamental flaw in his appeal: these issues are squarely within Environment Yukon’s regulatory mandate, not the Board’s.
55. Ultimately, the Board appropriately “stayed in its lane” in assessing YEC’s revenue requirement by considering YEC’s costs attributable to both to the permitted and unpermitted portions of its diesel generation capacity as part of its fact-driven, discretionary exercise of reviewing the reasonableness of YEC’s costs.

Broad Discretion Established by the Jurisprudence

56. The broad discretion the Board enjoys in assessing YEC’s costs and setting rates has been recognized in prior Board order appeals.

⁴³ Exhibit 5 at p. 20, RJAB Tab 5, p. 44.

⁴⁴ NY Factum at para. 24.

57. As this Court noted in *YEC v. YUB 2017*, “[u]nder most regulatory statutory schemes, discretion is central to the rate-setting process and the method by which it is accomplished is usually left with the regulators, who are experts.”⁴⁵
58. Like the present appeal, *YEC v. YUB 2017* also involved costs related to diesel generation. The issue was whether YEC should be permitted to recover costs associated with a diesel contingency fund (“**DCF**”) that protected ratepayers from fluctuations in electricity prices due to varying water levels for hydro generation and an associated need for expensive diesel generation.
59. This Court granted YEC’s appeal, remitted the matter to the Board, and directed the Board “to set a wholesale rate that enables [YEC] to recover all of its diesel generation costs, which include any net DCF payment....”⁴⁶ Although the present appeal is not concerned with wholesale rates, this Court’s repeated references to the Board’s broad discretion are relevant.⁴⁷
60. Similarly, the Court’s 2021 decision in another *Yukon Energy Corporation v. Yukon Utilities Board* appeal reviewed the Board’s exercise of its discretion when determining YEC’s rate base under section 32 of the *PUA* (another component of the rate-setting exercise).⁴⁸
61. In *YEC v. YUB 2021*, the Court found that the Board’s decision to decline to approve certain demand side management (or “**DSM**”) costs fell properly within the Board’s exercise of its discretion, in light of the Board’s determination that those DSM programs were not required to be used to provide service to the public. In dismissing YEC’s appeal, the Court concluded:⁴⁹

[33] As the Hearing Panel was entitled to exercise its discretion under s. 32(1) to decline to approve DSM costs to be part of Yukon Energy’s rate base, and as the Hearing Panel did not take into account any irrelevant factors in exercising its discretion, I conclude that it did not commit an

⁴⁵ *YEC v. YUB 2017* at para. 6.

⁴⁶ *YEC v. YUB 2017* at paras. 2 and 4.

⁴⁷ *YEC v. YUB 2017* at paras. 6, 18 and 57.

⁴⁸ *Yukon Energy Corporation v. Yukon Utilities Board*, 2021 YKCA 1 [*YEC v. YUB 2021*].

⁴⁹ *YEC v. YUB 2021* at para. 33.

error of law. The Hearing Panel was entitled to decline to approve any of the DSM costs for inclusion in the rate base other than the LED costs it did approve. It follows that the Review Panel did not make an error of law in dismissing Yukon Energy's review application.

62. The Supreme Court of Canada has affirmed the broad discretion afforded to rate-setters on several occasions, stating that under the Supreme Court's "rate-setting jurisprudence in other regulatory domains in which the regulator is given methodological discretion, ... it has been observed that '[t]he obligation to act is a question of law, but the choice of the method to be adopted is a question of discretion with which, under the statute, no Court of law may interfere.'"⁵⁰
63. The discretion afforded to regulators is tied to their specialized expertise: "the methodology for setting rates and the allocation of certain proceeds derived from those rates [is] a polycentric exercise with which the [regulator] is statutorily charged and which it is uniquely qualified to undertake."⁵¹
64. Similar to the Board, energy regulators in other jurisdictions, under their governing legislation, have been expressly found to have "broad discretion to set just and reasonable rates."⁵²
65. The discretion afforded to rate-setters is a critical aspect of the overarching powers granted to them under their governing legislation. As the Ontario Court of Appeal has framed the issue, "the [regulator]'s power in respect of setting rates is to be interpreted broadly and extends well beyond a strict construction of the task."⁵³

⁵⁰ *Ontario (Energy Board)* at para. 81, citing *Bell Canada v. Bell Aliant Regional Communications*, 2009 SCC 40 at para. 40 [**Bell Canada**].

⁵¹ *Bell Canada* at para. 38.

⁵² *Enbridge Gas Inc v. Ontario Energy Board*, 2020 ONSC 3616 at para. 42. See also: *Altagas* at paras. 21-22; *ATCO Gas and Pipelines Ltd v. Alberta Utilities Commission*, 2024 ABCA 400 at paras. 15-16; *Public Utilities Review Commission Act, Re*, 1986 CanLII 3233 (SKCA) at para. 17; *Manitoba Hydro-Electric Board v. Consumers' Association of Canada (Man.) Inc.*, 2012 MBCA 1 at para. 124; *Labrador City (Town) v. Newfoundland and Labrador Hydro Inc.*, 2004 NLCA 61 at para. 19.

⁵³ *Toronto Hydro-Electric System Limited v. Ontario Energy Board*, 2010 ONCA 284 at para. 25.

The Decision of the Board in Approving Diesel Rental Costs Was Appropriate

66. YEC strongly disputes Mr. Yee's assertion that the Board in this case provided "no reason or justification for accepting excessive and unpermitted capacity" for cost recovery.⁵⁴ The Board considered YEC's diesel rental units in their totality, including both permitted and unpermitted capacity. Its 2024 Reasons were cogent, and founded on the evidence it received and appropriately summarized in its reasons. Key portions of the Board's reasons include the following:⁵⁵

132. As noted in Section 4 of this Board Order, the Board has ruled on YEC's sales forecast and accepted YEC's forecast peak demand and dependable capacity. For production costs, no issues were identified by the Board or interveners regarding labour, hydro, LNG, or operation supervision costs. The Board has reviewed the information for these items and finds the costs reasonable and approves those costs as requested.

133. Regarding diesel costs, YEC has submitted that the diesel rental units represent the bulk of that cost category. YEC provided support for its diesel rental costs in Section 3.3.2 of the Application and its business case in Appendix 3.1 of the Application, as well as in its IR responses.

134. The Board has previously expressed several concerns regarding YEC's commitment to the rental diesel option and the quality of YEC's business cases. For example, concerns were expressed in Appendix A to Board Order 2022-03 (YEC's 2021 GRA), and in the Board's report regarding the YEC-THELP EPA.

135. In this proceeding, YEC provided a business case regarding the rented diesels. However, in the Board's view the business case contained certain shortcoming. For example, YEC compared the purchase cost of new, more environmentally friendly, Tier 4 diesel units to the rented diesel units which meet a lower standard (Tier 2) and effectively have a lower comparable cost. Secondly, when looking at a Tier 4 diesel unit, from an emissions and efficiency perspective, YEC accepted and continues to accept the lower Tier 2 performance of the rental units and did not include in its analysis a cost-benefit comparison between Tier 2 and Tier 4 diesel units and thus the effect on the LCOC of the diesel rental unit option.

136. At the time YEC entered into the diesel rental agreements, it was YEC's view that the BESS project, the Atlin EPA, and the Moon Lake projects would proceed according to forecast timelines. In accordance with

⁵⁴ NY Factum at para. 17.

⁵⁵ 2024 Reasons at paras. 132-138, AR Tab 2, pp. 119-121.

those timelines, YEC was of the view that N-1 capacity constraints existed in the short-term and that those short-term constraints were best resolved through short term rentals of diesels. The Board agrees that, based on the forecast timelines of the other clean energy projects, a short-term solution for the N-1 capacity shortfall was required. However, it now appears that YEC's forecast timelines for the above-mentioned projects were ambitious. In future, the Board expects YEC to provide stronger evidence regarding the timelines for such projects.

137. Mr. Yee has provided substantial comment on permitted capacity and whether ratepayers should pay for costs related to unpermitted capacity. Mr. Yee also commented on YEC's elasticity when determining the capacity rating of several of its thermal units. These submissions do not provide evidence the Board is able to use to determine the revenue requirement for YEC to provide safe and reliable electric service at rates that are in the public interest. It is incumbent upon YEC to ensure it has all required regulatory approvals, processes, and assets in place to provide that safe and reliable service. Regarding the capacity issues raised, YEC is directed, in its future applications, to provide a strong industry based and accepted approach on what the manufacturers accept as criteria and evidence for uprating thermal generation units. This can be based on documented industry standards.

138. In this proceeding, YEC has proven that a capacity shortfall exists on the YIS unless additional capacity is added. The Board accepts that in the short term, the only solution is rental diesel units. Therefore, the Board approves the rental costs for diesel units that YEC has applied for in this application.

67. As can be seen from these reasons, the Board's consideration of YEC's diesel rental unit costs was a fact-driven inquiry that considered the business case for rental diesel units, evidence of emergency capacity shortfalls, the responsibility for regulatory approvals resting with other regulators, and available solutions for addressing capacity shortfalls on the YIS. The Board's weighing of these factors was a discretionary exercise at the heart of the Board's specialized jurisdiction and expertise under the *PUA*.
68. The Board's 2024 Reasons must also be read in the context of its earlier 2022 Reasons for Board Order 2022-03, following YEC's 2021 GRA. The Board's 2022 Reasons (addressed below) further explain the Board's rationale for allowing YEC

to recover its costs for unpermitted diesel rental unit capacity in the face of nearly identical arguments made by Mr. Yee.

69. Ultimately, the Board's Decision was based on its evaluation of YEC's evidence providing its business case for why those assets are required to address the N-1 capacity shortfall and potential emergency conditions, in order to ensure YEC's ability to provide reliable service to customers, as well as evidence of specific instances when those assets have in fact been used to ensure continuity of service and to prevent harm to public welfare, health and safety during emergency events resulting from unplanned outages during extreme cold winter weather conditions.
70. The two specific examples of recent instances when emergency diesel generation in excess of YEC's permitted capacity was required – the December 2022 and January/February 2024 emergency events – provided concrete evidence to the Board for why maintaining this emergency capacity was reasonable and necessary. Those two specific examples also afforded the Board illustrative evidence of YEC reporting its exceedances on both occasions to Environment Yukon, the regulatory body mandated to address these issues, enabling Environment Yukon to determine what if any further regulatory response was needed within its own mandate.
71. It was not the Board's role to grant (or deny) permission for YEC to exceed any capacity limits established by Environment Yukon; nor did the Decision purport to grant any such permission to YEC. Instead, the Board appropriately left those issues for the appropriate regulator (Environment Yukon), saying, "[i]t is incumbent upon YEC to ensure it has all required regulatory approvals."⁵⁶
72. The Board's Decision does not "usurp" Environment Yukon's authority, as Mr. Yee argues. In fact, the exact opposite is true: by appropriately staying within its own regulatory mandate and noting that it is incumbent on YEC to ensure the required regulatory approvals (from Environment Yukon) the Board expressly

⁵⁶ 2024 Reasons at para. 137, AR Tab 2, p. 120.

acknowledged the limits of its own mandate, while acknowledging and respecting that of Environment Yukon.

Prior Decision of the Board Allowed Unpermitted Diesel Rental Costs

73. As noted, the Decision under review is not the first time that the Board has approved costs associated with diesel generation capacity exceeding the normal operating capacity authorized by YEC's Air Emissions Permits.
74. The current Decision is in line with the Board's decision on the 2021 GRA. After addressing the same arguments raised by Mr. Yee as intervenor in that proceeding, the Board allowed YEC to recover costs associated with diesel generation units in excess of YEC's air emissions permits, reasoning as follows:⁵⁷

107. Mr. Yee alleged that YEC is in violation of the Yukon Environmental and Socioeconomic Assessment Act and the [Yukon Socio-Economic Assessment Board ("YESAB")] permit granted to YEC. The Board does not have jurisdiction over YEC's licences approved by YESAB. For clarity, the Board's statutory mandate is to set YEC's just and reasonable rates, and the Board's analysis and findings are necessarily limited to its mandate.

108. The Board does not agree with Mr. Yee's recommendation of excluding the diesel rental unit costs from rate base and excluding the diesel rental units from N-1 events, even if the rentals at issue did not have authorization from YESAB. The Board finds YEC's explanation that it connected the additional rental units to resolve an N-1 dependable capacity shortfall event, not to increase its normal operation capacity, to be credible. The Board accepts YEC's statement that rental of these diesel units was necessary to connect sufficient dependable capacity in the winter to keep customers connected to electricity during an extended cold weather event under N-1 emergency conditions. In the Board's view, this action by YEC is consistent with its statutory obligations to provide service to customers. The Board finds that excluding additional diesel units, other than the two spare backup units, from N-1 events would hinder YEC's provision of reliable service.

⁵⁷ 2022 Reasons at paras. 107-108, citations omitted, RJAB Tab 8, p. 159.

Conclusion

75. In summary, the Board's approval of YEC's diesel rental costs was a valid exercise of its broad discretion to approve operating costs for inclusion in YEC's revenue requirement. The Board's review and acceptance of those costs fell squarely within the performance of its statutory duty to approve just and reasonable electricity rates that are sufficient to allow YEC to recover its estimated reasonable operating costs.
76. Mr. Yee has not identified any provision in the *PUA* or its regulations that the Board purportedly misinterpreted or misapplied that could constitute an error of law or jurisdiction, or that could justify interference with the Board's decision. Rather, Mr. Yee's submissions ask this Court to impose an additional regulatory mandate on the Board that is foreign to its governing legislation, in circumstances where a separate regulator (Environment Yukon) is already tasked with the specific mandate sought to be imposed on the Board. This is clearly inappropriate.
77. There is no basis to disturb the Decision. The appeal should be dismissed.

PART 4**NATURE OF ORDER SOUGHT**

78. YEC seeks an order dismissing the appeal with costs payable to YEC.

ALL OF WHICH IS RESPECTFULLY SUBMITTED



Jason Herbert
Counsel for the Respondent,
Yukon Energy Corporation

June 18, 2025
Vancouver, BC

APPENDICES

PUBLIC UTILITIES ACT, R.S.Y. 2002, c. 186

1 Interpretation

(1) In this Act,

“board” means the Yukon Utilities Board established by section 2;

“compensation” means a rate, remuneration, gain, or reward of any kind paid, payable, promised, demanded, received, or expected directly or indirectly by a public utility, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it;

“costs” includes fees, counsel fees, and expenses;

“customer” refers to a purchaser of electricity;

“excluded undertaking” means a prescribed undertaking or an undertaking that consists only of

(a) generation and distribution by a person of electricity, if

(i) the electricity is consumed only by the person, their employees or their tenants, and

(ii) if the electricity is generated on one property and consumed on another

(A) the electricity is carried between the properties by a transmission or distribution line that the person owns and operates, and

(B) the resulting electrical system

(I) is connected with the facilities neither of a public utility nor of any other customer, and

(II) does not duplicate any existing or planned facility of a public utility,

(b) engagement in the petroleum industry or in the well-head production of oil, natural gas, or other natural petroleum substances, or

(c) the sale or delivery of gas otherwise than by a pipeline;

“expenses” includes expenses of the board;

“gas” means methane and propane;

“member” means a member of the board;

“methane” means, in addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide;

“propane” means, in addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane or butanes;

“public hearing” means a hearing of which public notice is given, which is open to the public, and at which any person the board determines has an interest in the matter may be heard;

“public utility” means a person who, otherwise than in an excluded undertaking

(a) in the Yukon, for consideration, produces, generates, stores, transmits, sells, delivers or furnishes electricity or gas, or

(b) owns equipment or facilities that are used to do anything described in paragraph (a);

“rate” includes a general, individual, or joint rate, fare, toll, charge, rental, or other compensation charged or chargeable by a public utility, any rule, regulation, practice, measurement, classification, or contract of a public utility relating to a rate, and any schedule or tariff respecting a rate;

“service” includes the use and accommodation provided and a product or commodity furnished by a public utility, and also the plant, equipment, apparatus, appliances, property, and facilities employed by or in connection with a public utility in providing service or in furnishing a product or commodity for the purposes in which the public utility is engaged.

(2) In this section, a reference to a person includes any lessee, trustee, receiver or liquidator of the person.

[S.Y. 2014, c.3, s.2] [S.Y. 2002, c. 186, s. 1]

PART 2

REGULATION OF PUBLIC UTILITIES

27 Board orders

The board may make orders

(a) setting rates of a public utility;

(b) prohibiting or limiting any proposed rate change;

(c) setting proper and adequate rates and methods of depreciation, amortization, or depletion in respect of the property of any public utility;

- (d) setting just and reasonable standards, classifications, regulations, practices, measurements, or services to be observed, provided, or followed by a public utility;
- (e) determining the areas to which a public utility shall provide service, and requiring the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services; and
- (f) determining the conditions that may be imposed by a public utility to establish, construct, maintain, or operate an expansion of its existing services.

[S.Y. 2002, c. 186, s. 27]

28 Rate changes

(1) No public utility shall charge any rate for the supply of the service for which it is franchised other than the rate set by the board pursuant to this Act unless, 90 days before it proposes to charge a different rate,

- (a) a statement showing the new rate is filed with the board; and
- (b) a notice showing the new rate is sent by mail or delivered to each municipality in which the service is provided and to the Minister.

(2) No public utility shall begin to charge a new rate except on receipt from the board of an order or interim order authorizing it to do so.

[S.Y. 2002, c. 186, s. 28]

29 Factors affecting rates

In setting rates that a public utility is permitted to charge,

- (a) the board may consider the revenues and costs of the public utility in the financial year in which the proceedings for setting the rates and charges began or in any period immediately following, without considering the allocation of those revenues and costs to any part of that period;
- (b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable;
- (c) the board may give effect to any part of any excess revenue received or deficiency incurred after the commencement of the proceeding as the board determines has been due to undue delay in the hearing and determining of the matter; and

(d) the board shall by order approve the method by which and the period during which any excess revenue received or deficiency incurred is to be used or dealt with.

[S.Y. 2002, c. 186, s. 29]

32 Rate base of public utilities

(1) The board, by order, shall determine a rate base for the property of a public utility used or required to be used to provide service to the public, and may include a rate base for property under construction, or constructed or acquired, and intended to be used in the future to provide service to the public.

(2) The board, by order, shall set a fair return on the rate base.

(3) In determining a rate base the board shall give due consideration to the cost of the property when first devoted to public utility use, to prudent acquisition cost less depreciation, amortization, or depletion, and to necessary working capital.

(4) In setting the fair return that the public utility is entitled to earn on the rate base, the board shall give due consideration to all those facts that in the opinion of the board are relevant.

(5) Despite the other provisions of this section, the board may adopt any just and reasonable basis for determining a method of calculating a fair return on property that is being constructed or that has been constructed or acquired but is not yet being used to provide service to the public.

[S.Y. 2002, c. 186, s. 32]

PART 4 ADMINISTRATION AND ENFORCEMENT

APPEALS

69 Leave to appeal to the Court of Appeal

(1) On application to the Court of Appeal within 30 days of a decision or order of the board or within a further time allowed by the Court of Appeal in special circumstances, the Court of Appeal may grant leave to appeal to that court from the order or decision on a question of law or excess of jurisdiction.

(2) The granting of leave to appeal and the costs of the application are in the discretion of the Court of Appeal.

(3) The applicant shall give notice of the application stating the grounds of appeal to the board, to the Minister, and to any party adverse in interest, at least three clear days before the hearing of the application.

[S.Y. 2002, c. 186, s. 69]

70 Appeal procedure and costs

(1) If leave is granted, the appellant shall, within 15 days, give notice of appeal to the board, to the Minister and to any party adverse in interest.

(2) The board and the Minister may be heard by counsel on the appeal.

(3) Neither the board nor an officer, employee, or agent of the board is liable for costs in respect of an application or appeal under this section.

[S.Y. 2002, c. 186, s. 70]

71 Effect of order or decision under appeal

An appeal to the Court of Appeal shall not of itself stay or suspend the operation of the decision or order appealed from, but either the Court of Appeal or the board has the power to suspend the operation of the decision or order on any terms set by the court or the board, as the case may be.

[S.Y. 2002, c. 186, s. 71]

72 Jurisdiction of the Court of Appeal

(1) The Court of Appeal has the same jurisdiction and powers on appeals as it has for appeals from orders of the Supreme Court.

(2) Except as otherwise provided in this Act, appeals shall conform as far as possible with the rules governing appeals from the Supreme Court.

[S.Y. 2002, c. 186, s. 72]

74 Hearing and determination of appeals

An application, appeal, or reference to the Court of Appeal under this Act shall be heard and determined without delay in a summary way.

[S.Y. 2002, c. 186, s. 74]

**PART 5
PUBLIC UTILITY COMPANIES****106 Duty of company to supply utility service**

All companies having the privileges conferred by this Part shall supply the utility controlled by them to all persons within the area covered by the privilege except in those cases where the company may lawfully refuse to supply the utility.

[S.Y. 2002, c. 186, s. 106]

**RATE POLICY DIRECTIVE (1995),
O.I.C. 1995/090**

1. Interpretation

In this Directive

“customer” refers to a purchaser of electricity;

“government customer” means a retail customer

(a) who is a federal or territorial department or agency;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a);

“isolated industrial customer” means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer;

“major industrial customer” means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer;

“natural gas” includes liquefied natural gas;

[“natural gas” added by O.I.C. 2018/220]

“province” has the same meaning as in the *Interpretation Act*;

“renewable generation” means generation of electricity from renewable sources, including hydro, wind, solar, geothermal and biomass sources;

[“renewable generation” added by O.I.C. 2021/16]

“retail customer” means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer;

“wholesale customer” means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation.

2. Normal return on equity

(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity.

[Section 2 replaced by O.I.C. 1998/32]

3. Normal principles to apply

Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

4. Retail rates: non-government customers

(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

(a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non- government retail customers.

(3) The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non- government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

6. Rates - major and isolated industrial customers

(1) The Board must ensure that the rates charged to major industrial customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

[Subsection 6(1) amended by O.I.C. 2018/220]

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to section 2.1.

[Subsection 6(3) added by O.I.C. 2007/94]

[Subsection 6(3) replaced by O.I.C. 2012/68]

[Subsection 6(3) amended by O.I.C. 2014/23]

[Subsection 6(3) replaced by O.I.C. 2018/220]

7. Wholesale rates

The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

***ENVIRONMENT ACT,
R.S.Y. 2002, c. 76*****PART 9
RELEASE OF CONTAMINANTS****113 Report of release**

Every person who releases a contaminant in an amount, concentration, or level in excess of that prescribed by regulation or allowed under a permit shall, as soon as possible under the circumstances, report the release to an environmental protection officer or to a person designated by regulation.

[S.Y. 2002, c. 76, s. 113]

**YUKON ENVIRONMENTAL AND SOCIO-ECONOMIC ASSESSMENT ACT,
S.C. 2003, c. 7**

PART 2**Assessment Process and Decision Documents****Proposed Activities Subject to Assessment****Emergencies exempted**

49 (1) Notwithstanding sections 47 and 48, no assessment is required of an activity that is undertaken in response to a national emergency for which special temporary measures are being taken under the *Emergencies Act*, or in response to an emergency when it is in the interest of public welfare, health or safety or of protecting property or the environment that the activity be undertaken immediately.

Reporting after emergencies

(2) As soon as practicable after any such activity is completed, the person who undertook it shall send a written report to the designated office for each assessment district in which it was undertaken describing the nature, extent and duration of the activity and any work required in order to restore or rehabilitate the area affected by it.

LIST OF AUTHORITIES

Cases	Para(s).
<i>1193652 B.C. Ltd. v. New Westminster (City)</i> , 2021 BCCA 176	28
<i>Altogas Utilities Inc. v. Alberta Utilities Commission</i> , 2020 ABCA 375	24, 64
<i>ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)</i> , 2006 SCC 4	40, 41
<i>ATCO Gas and Pipelines Ltd v. Alberta Utilities Commission</i> , 2024 ABCA 400	64
<i>Bell Canada v. Bell Aliant Regional Communications</i> , 2009 SCC 40	62, 63
<i>Canada (Minister of Citizenship and Immigration) v. Vavilov</i> , 2019 SCC 65	26-28
<i>Enbridge Gas Inc v. Ontario Energy Board</i> , 2020 ONSC 3616	64
<i>Housen v. Nikolaisen</i> , 2002 SCC 33	26
<i>Labrador City (Town) v. Newfoundland and Labrador Hydro Inc.</i> , 2004 NLCA 61	64
<i>Liberal Party of Canada v. The Complainants</i> , 2024 BCSC 814	29
<i>Manitoba Hydro-Electric Board v. Consumers' Association of Canada (Man.) Inc.</i> , 2012 MBCA 1	64
<i>Ontario (Energy Board) v. Ontario Power Generation Inc.</i> , 2015 SCC 44	40, 62
<i>Public Utilities Review Commission Act, Re</i> , 1986 CanLII 3233 (SKCA)	64
<i>Toronto Hydro-Electric System Limited v. Ontario Energy Board</i> , 2010 ONCA 284	65
<i>Utilities Consumers' Group v. Yukon Utilities Board</i> , 2001 YKCA 5, aff'd 2002 YKCA 8	25
<i>Yee v. Yukon Energy Corporation</i> , 2024 YKCA 13	Chronology
<i>Yee v. Yukon Energy Corporation</i> , 2025 YKCA 3	Chronology, 23

<i>Yukon Energy Corporation v. Yukon Utilities Board</i> , 2017 YKCA 15	33, 40-42, 57-59
<i>Yukon Energy Corporation v. Yukon Utilities Board</i> , 2021 YKCA 1	60, 61
Yukon Utilities Board Order 2022-03	Chronology, 8, 9, 11, 37, 68, 74

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) On p. 454 of Vol 3 of the transcript for the 2021 GRA, as part justifying rental diesel,
6 YEC was insistent that building a new diesel plant in or around Whitehorse would
7 take four years. YEC is now claiming that a new plant can be open in two years, in
8 2027. What has changed, other than that YEC is now claiming that permanent
9 diesel rather than rental diesel is the only feasible option?

10
11 **ANSWER:**

12
13 **(a)**

14
15 The 2021 GRA question referred to the timeline to plan, permit and construct a 20-
16 megawatt diesel plant as opposed to site infrastructure to accommodate mobile diesel
17 units.

18
19 Without a specific reference to the current 2025-2027 Application, Yukon Energy has
20 made the assumption that Mr. Yee is referring to point 1 on PDF page 441 of the
21 Application, where Yukon Energy describes its near-term plan to build a diesel site in south
22 Whitehorse in 2026/27 to accept up to 15 MW of diesel generation capacity, with diesel
23 rentals to be added to that site to meet load growth until the larger proposed site in north
24 Whitehorse is brought in-service.

25
26 Yukon Energy's Application does not state that "permanent diesel rather than rental diesel
27 is the only feasible option." The information provided on PDF page 441 of the Application
28 simply outlines plans to develop up to three thermal generation sites in and around
29 Whitehorse over the next decade to add sources of dependable winter capacity to the grid
30 and meet growing demands for winter power.

31
32 The time it takes to build a new thermal generation site is based on several factors
33 including but not limited to how the site is engineered and designed. Sites without buildings
34 or where thermal generation assets are modular or mobile in nature typically require less
35 time to build than sites with buildings or where thermal generation assets are stored inside
36 manufactured buildings. Other considerations may include fuel type, supply chain

- 1 availability, geotechnical conditions of the site, availability of labour, complexity of site
- 2 interconnection with the greater system, etc.
- 3
- 4 For more information, including updates, on the WPCP please see YUB-YEC-1-8.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

- 4
5 a) It is noted that YEC is now pursuing longer term rental of the diesels and/or
6 reserving years in advance. Please outline reasoning and provide specifics
7 concerning differences in cost – and why this is happening now and has not
8 happened previously.

9
10 **ANSWER:**

11
12 **(a)**

13
14 With the development of Yukon Energy's Road Map,¹ Yukon Energy has plans to use
15 rentals until more permanent sources of dependable winter power are online.

16
17 Yukon Energy is looking to pursue mobile diesel rentals over a longer-term contract to
18 minimize risk of the rental diesel units (and the power they provide) not being available to
19 be rented in a future year. In addition, annual procurement of mobile diesel rentals is a
20 time-consuming process that costs Yukon Energy staff time and resources. Entering into
21 multi-year contracts is more efficient and allows staff time and resources to be redirected
22 to other priorities. Also, with the implementation of a multi-year rental period, mobilization
23 and demobilization costs can be reduced.

24
25 Decisions made in the past and recently have been made based on the information
26 available at the relevant time.

¹ Please see the response to YUB-YEC-1-8 a) and b) for details.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) How does YEC plan to address noise issues in Faro?

6
7 **ANSWER:**

8
9 **(a)**

10
11 Yukon Energy has implemented noise mitigations, such as re-positioning the rental diesel
12 generators in 2023. In doing so, the loudest part of the generators is facing away from the
13 town centre, and sound is buffered by the building that houses the generator FD1. Based
14 on sound noise monitoring data, these changes have improved noise levels in the
15 community.

16
17 Yukon Energy continues to monitor sound levels in the community and is aware of the
18 terms in the Decision Document for YESAA Project 2024-0145 related to noise from the
19 diesel engines. Yukon Energy is investigating options for noise mitigation and will provide
20 an update to the community as more information becomes available.

21
22 It should be noted that there is no noise legislation in the Yukon applicable to Yukon
23 Energy operations. Yukon Energy follows the British Columbia Noise Control Best
24 Practices Guideline; however, as part of this guideline, Permissible Sound Levels do not
25 apply in emergency situations where public safety is at risk.

1 **REFERENCE: 2025-27 YEC GRA Information Requests**

2
3 **QUESTION:**

4
5 a) What are the lessons learned from the failure to make meaningful progress with
6 significant renewables (Moon Lake and Atlin), and what can be done to make
7 renewable projects successful in the future?

8
9 **ANSWER:**

10
11 **(a)**

12
13 Please see YUB-YEC-1-59(b).

**UTILITIES CONSUMERS' GROUP
(UCG)**

1 **REFERENCE: Application dated May 12, 2025**

2
3 **QUESTION:**

4
5 a) Explain why the application was not submitted until May 2025, midway through the
6 2025 test year.

7
8 b) When did Yukon Energy first identify revenue requirement issues?

9
10 **ANSWER:**

11
12 **(a) and (b)**

13
14 The Compliance Filing for the 2023/24 General Rate Application was not approved by the
15 Board until September 13, 2024. Yukon Energy commenced preparation of its 2025-27
16 General Rate Application as soon as feasible after that date.

17
18 Specifically, as noted in Tab 4, footnote 1, Yukon Energy updated its forecasts and
19 finalized its 2025 Business Plan in December of 2024. Updates and adjustments for 2025,
20 2026 and 2027 were performed in January through March 2025 with a plan to file in March
21 2025. The addition of a third year also resulted in more time required to prepare the
22 Application. At the request of Yukon Government, the submission date was slightly
23 delayed to May 2025 as Yukon Energy explored options to reduce the requested rate
24 increase.

25
26 In the absence of capital grant funding, Yukon Energy foresees revenue requirement
27 shortfalls each year for the foreseeable future.

1 **REFERENCE: Application dated May 12, 2025**

2
3 **QUESTION:**

4
5 a) Summarize any Yukon Energy Corporation customer or stakeholder consultations
6 conducted before submitting this application to the YUB.

7
8 b) Provide all documents from these consultations, including a list of participants.

9
10 c) If consultations occurred, explain how input was used in the application.

11
12 d) State how Yukon Energy notified ratepayers of proposed rate increases for each
13 test year.

14
15 **ANSWER:**

16
17 **(a) to (c)**

18
19 Yukon Energy consulted with intervenors of previous applications, Utilities Consumer
20 Group and John Maissan, as well as the Yukon Chamber of Commerce and many First
21 Nation governments. There were no official documents resulting from these consultations.
22 Information obtained during these consultations were considered with all other information
23 available, and decisions were made in the best interests of Yukoners.

24
25 **(d)**

26
27 Please see Yukon Energy response to NY-YEC-1-20.

1 **REFERENCE: Cover Letter dated May 12, 2025**

2
3 **QUOTE:** "The GRA deals primarily with Yukon Energy's revenue requirement
4 needed to carry out its responsibilities. It does not address in any
5 material way cost of service and general rate design matters that would
6 require joint work with ATCO Electric Yukon (AEY)."
7

8 **QUESTION:**

9
10 a) What are YEC's responsibilities? Explain prioritizing customer interests.

11
12 b) Why weren't cost of service and rate design issues included in this application, and
13 when will they be addressed jointly with AEY?
14

15 **ANSWER:**

16
17 **(a)**

18
19 Yukon Energy is the main generator and transmitter of electricity in Yukon. It is responsible
20 for ensuring the Yukon Integrated System has a supply of safe, reliable and sustainable
21 electricity to meet Yukoner's needs, and for filing GRA's as required to provide approved
22 revenue requirements and overall rates that will enable Yukon Energy to supply safe,
23 reliable and sustainable electricity to meet Yukoner's needs.
24

25 **(b)**

26
27 The Yukon Energy GRA Application can only deal with revenue requirement and rate
28 matters applicable solely to Yukon Energy. Given the Rate Policy Directive (OIC 1995/90),
29 any cost of service and rate design matters would require the Yukon Utilities Board to
30 establish a separate joint proceeding involving both Yukon Energy and AEY – and such a
31 proceeding would also require YUB concurrent approval of both Yukon Energy and AEY
32 revenue requirements for at least one common test year.
33

34 The following are also noted in this regard:

- 35
36 • In Order 2010-13 the Board did not accept the last joint Cost of Service Study
37 provided by the Companies for 2009, noting at paragraph 29: "The Board agrees

1 with the City of Whitehorse's view that an updated COS study approved by the
2 Board is essential to establishing a future rate restructuring process. Therefore,
3 the Board directs the Companies to file a joint COS study within six months of the
4 expiry of OIC 2008/149." OIC 2008/149 prevented the YUB until after December
5 31, 2012 from rebalancing rates among customer rate classes to reflect cost of
6 service, i.e., until that deadline, percentage rate changes had to be the same for
7 all classes of retail customers and for the class of major industrial customers. The
8 City of Whitehorse had submitted that the expiry of OIC 2008/149 should drive a
9 new COS study, which it saw as essential to any future rate restructuring process.

- 10
- 11 • Further OIC's after OIC 2008/149 have in effect moved out the timeline in the
12 Board's above direction in Order 2010-13 regarding the Companies' filing another
13 joint COS study.

- 14
- 15 ○ OIC 2012/68 extended to December 31, 2013 the prior prevention of any
16 rebalancing of rates among customer rate classes, thereby covering the
17 period for YEC's 2012-2013 GRA and its overlap with the AEY 2013-2015
18 GRA; and
 - 19 ○ OIC 2018/13 subsequently re-established, without any term end date, the
20 direction preventing the YUB from rebalancing rates among customer rate
21 classes to reflect cost of service. This direction is provided today in the
22 amended OIC 1995/90 Rate Policy Directive, clause 2.1(1).

23

24 The last common test year for Yukon Energy and AEY GRAs was in 2023-2024, at which
25 time no directions or proposals were provided for the Companies to provide a joint COS
26 study.

1 **REFERENCE: Cover Letter dated May 12, 2025**

2
3 **PREAMBLE:** YEC plans to increase electricity rates in 2025, 2026, and 2027 to invest
4 in Yukon's electricity system. These investments aim to expand
5 renewable infrastructure, increase winter supply, and improve the
6 system for evolving customer needs.
7

8 **QUESTION:**

9
10 a) To ensure transparency and effective planning Provide a year-by-year schedule of
11 all forecasted O&M costs for 2025–2027. Note which YEC objectives (safe,
12 reliable, sustainable, affordable) each cost supports to provide a clearer
13 understanding behind the expenditures.
14

15 b) To ensure transparency and effective planning provide a year-by-year schedule of
16 all capital costs for 2025-2027. Note which of YEC objectives (safe, reliable,
17 sustainable, affordable) each cost supports to provide a clearer understanding
18 behind the expenditures.
19

20 c) On the same schedule for capital costs list the system areas (generation,
21 transmission, distribution, storage, grid stability, end-use) linked to each capital
22 expenditure for 2025–2027.
23

24 **ANSWER:**

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

27
28 Year by year schedules are provided in Tab 2, Tab 3 and Tab 5 of the application and
29 address sales and generation, O&M and capital costs. Costs associated with safe, reliable
30 and sustainable supply are inherent in all costs of YEC.
31

32 Capital projects are planned and prioritized through a rigorous capital planning process.
33 This process was developed through an improvement project and was implemented in
34 2022. All proposed projects are ranked and prioritized to develop a capital program that
35 maximizes the benefit of capital investments and minimizes the operational risks to the
36 corporation. The impact criteria used ensures that projects ranking high in safety, reliability
37 and sustainability are more likely to receive capital funding.

1 Additionally, work completed with capital and O&M dollars is subject to federal and
2 territorial legislation, and electrical utility codes and standards that drive safety, reliability
3 and sustainability. Federal and territorial legislation is varied with key pieces of legislation
4 impacting capital and O&M spending. Examples of significant pieces of legislation are the
5 Yukon Environmental and Socio-economic Assessment Act, the Yukon Waters Act, the
6 Workers' Safety and Compensation Act, the Yukon Environment Act, the Federal
7 Fisheries Act, and the Migratory Birds Convention Act.

8
9 Electrical utility codes and standards govern the design, installation, maintenance, and
10 safety of electrical systems. These codes and standards are established to make sure
11 utilities operate safety, reliability and sustainability.

12
13 Canada's rigorous legislative and regulatory regime combined with the stringent codes
14 and standards require safety, reliability and sustainability to be considered and prioritized
15 in planning capital and O&M spending.

16
17 **(c)**

18
19 Aspects of the electricity system being addressed by each of the forecast capital
20 expenditures in in 2025, 2026 and 2027 are provided in the Application in Tables 5.5 to
21 5.7.

1 **REFERENCE: Cover Letter dated May 12,2025**

2
3 **ISSUE:** Proposed Timing for Interim and Final Rates & Bill Impact Mitigation

4
5 **QUOTE:** “Average monthly bills in Yukon remain the lowest across the North,
6 and Yukon Energy is committed to doing what it can to keep it that way.”

7
8 **PREAMBLE:** YEC then goes on to state that they are attempting to provide bill impact
9 mitigation by applying for government grant funding and timing one
10 increase with another rate adjustment retiring.

11
12 **QUESTION:**

13
14 a) Clarify how comparing Yukon’s bills to those in other regions justifies increases.

15
16 b) Explain when and how government grant funding will lower customer bills.

17
18 c) Specify when and how bill adjustment timing reduces customer bills.

19
20 **ANSWER:**

21
22 **(a)**

23
24 Bill information is not used to justify rate increases. Justification for rate increases are
25 discussed thoroughly in the Application. The bill information provided in the application
26 demonstrates that at current levels or with proposed increases Yukon rates and bills are
27 lower relative to other similar jurisdictions in the north.

28
29 **(b)**

30
31 Please see Yukon Energy’s response to YUB-YEC-1-10 (e) and (f).

32
33 **(c)**

34
35 See Section 1.1.7 and Section 4.1.2 of the Application. Seeking approval of interim rate
36 increases and final rate adjustments to occur at the earliest possible time within a test
37 year, and when other charges are expected to be removed from bills, reduces the impact

1 of rate increases, and provides greater bill stability and predictability for Yukoners. More
2 specifically (and as noted in the application):

- 3
- 4 • The earlier the interim rates are approved and implemented during a GRA review,
5 the lower the overall bill increase that results as it spreads the rate increase over
6 a larger number of months and minimizes the required true-up at the end. This is
7 one of the reasons Yukon Energy proposes higher interim rate requests in this
8 Application.
9
 - 10 • Yukon Energy is seeking approval of the 2025-27 GRA final rates for the 2025 and
11 2026 test years and true-up rider, if required, effective April 1, 2026, and final 2027
12 test year rates effective January 1, 2027 as this will enable coordination of the rate
13 increase with the removal of the 2023/24 Yukon Energy GRA true-up Rider J1 of
14 9.45% which is in effect until December 31, 2026. This will minimize rate shock
15 and provide greater bill stability to Yukoners.

1 **REFERENCE: Cover Letter dated May 12,2025**

2
3 **ISSUE:** Proposed Timing for Interim and Final Rates & Bill Impact Mitigation

4
5 **QUOTE:** "The timing and amount of interim rate increases has a large impact on
6 the amount of the true-up rider required further in the process."
7

8 **PREAMBLE:** To give a better understanding of the implications of interim rate
9 increases, address the following questions and issues:
10

11 **QUESTION:**

12
13 a) List all reasons a true-up rider is required, explaining each.

14
15 b) Is application timing a key factor? Explain.

16
17 c) How does Yukon Energy suggest addressing this lag?
18

19 **ANSWER:**

20
21 **(a) to (c)**

22
23 See the discussion provided in Section 1.1.7 and Section 4.1.2 of the Application. A true
24 up rider is required to collect revenue short falls during a test year where the amount of
25 revenues collected over the year are lower than the revenues that would be collected with
26 approved rates. This short fall may occur due to: interim rates being lower than the final
27 approved rate; and/or delays in implementing interim rates (such that revenues are only
28 collected over a partial year). Such delays may occur due to filing the application during
29 the test year and/or due to delays in approving interim rates.
30

31 Yukon Energy has outlined in its application measures it is implementing to mitigate
32 impacts related to true up riders (see Sections 1.1.7 and 4.1.2).
33

- 34 • Yukon Energy is seeking approval of interim rate increases and final rate
35 adjustments to occur at the earliest possible time within a test year, and when other
36 charges are expected to be removed from bills. This would reduce the impact of
37 rate increases, providing greater bill stability and predictability for Yukoners.

- 1 • Yukon Energy has submitted the current GRA Application as early in the year as
2 possible (subject to various levels of submission approval) to allow for an interim
3 Rider to be effective July 1 of the first test year. In the Application Yukon Energy
4 has noted that this may be improved in the next GRA by submitting in the year
5 prior to the first test year. To assist with increasing the likelihood of this occurring,
6 the 2025-27 GRA is for three test years which should allow sufficient time between
7 Board approval of this GRA, and preparation time required for the next GRA.

1 **REFERENCE:** Application, Table 1-1: Proposed Rate Changes and Expected Bill
2 Impacts Board Order 2025-12 - YEC Interim Refundable Rates
3 Approach for Current Rate Application p1-10
4

5 **QUOTE:** "Yukon Energy's approach for the timing of rate increases is based on
6 feedback received during and since the previous GRA. Yukon Energy
7 has heard from interveners that ratepayers value predictability
8 (understanding timing for rate changes) and stability (i.e., want to know
9 rates in advance want smooth rate increases across test years, and to
10 avoid or minimize rate true-ups."
11

12 **PREAMBLE:** The Board memo denying a variance ratepayer request that would
13 delay rate increases scheduled for January 1, only six months after the
14 July 1, 2025 increase.
15

16 **QUESTION:**
17

- 18 a) Please provide documentation or records of feedback from interveners regarding
19 their views on predictability and stability of rates.
20
21 b) Provide evidence supporting that this application achieves predictability for
22 ratepayers.
23
24 c) Provide evidence that stability is attained using interim and true-up riders.
25
26 d) Provide evidence that Yukon Energy's approach facilitates a smooth rate increase
27 environment throughout the test years. Please explain how the occurrence of two
28 10 percent bill increases within a six-month period, subsequent billing adjustments
29 due to any interim refundable decisions, the finalization of an additional 10 percent
30 bill increase, and the implementation of a true-up smooths rates.
31

32 **ANSWER:**
33

34 **(a)**
35

36 After completion of the 2023/24 GRA, Yukon Energy consulted with intervenors of
37 previous applications, Utilities Consumer Group and John Maissan. There were no official
38 documents resulting from these consultations.

1 UCG's comments and questions provided documentation regarding its views on
2 predictability and stability of rates during the 2023/24 GRA at the following times:

- 3
- 4 • As part of UCG's submission on YEC interim riders;
 - 5 • As part of UCG's cross-examination performed by Mr. Rondeau;
 - 6 • As part of UCG's submission of its final argument; and
 - 7 • As part of UCG's submission of its reply argument.
- 8

9 **(b) to (d)**

10

11 See the discussion provided in Section 1.1.7 and 4.1.2 of the Application which outline in
12 detail the options reviewed and the specific rationale for the 3-year rate increases and the
13 specified timing and quantum for each rate increase.

1 **REFERENCE:** Summary of Requested Orders, Yukon Energy Application, p. 6

2
3 **QUOTE:** "Return on Rate Base...Approval of \$23.751million in 2025,
4 \$30.408million in 2026 and \$37.571million in 2027 including an
5 allowed return on equity of 9.15% for each test year."
6

7 **PREAMBLE:** Return on Equity (pp. 8.1 to 8.6):
8 Yukon Energy proposes adopting the BCUC GCOC benchmark return
9 on equity of 9.65%, without a premium adder, adjusted by the OIC. For
10 benchmarking purposes, Yukon Energy has selected FortisBC Inc.
11 (Electric) (FEI) and ATCO Electric Yukon (AEY) as comparable utilities.
12

13 **QUESTION:**
14

- 15 a) Provide an analysis of the operational performance of Yukon Energy compared to
16 FEI and AEY. Each evaluation should illustrate how the respective company
17 achieves efficiency and cost-effectiveness in delivering electricity to its customers.
18
- 19 b) Provide more details on best practices within the electric utility industry and how
20 Yukon Energy adheres to these practices.
21
- 22 c) Utilizing the data from Table 8.1 and Table 8.2, explain the rationale for comparing
23 FEI and AEY's operations with those of Yukon Energy. Explain how these
24 operations are comparable.
25
- 26 d) Submit the SAIDI and SAIFI reliability reports for 2024 including any significant
27 changes or trends observed in these metrics.
28
- 29 e) List recent investments, including dollar amounts, aimed at reducing transmission
30 losses.
31
- 32 f) List all investments addressing generation capacity constraints.
33
- 34 g) Describe the methods Yukon Energy employs to communicate tariff and fee
35 changes to end-users.

1 **ANSWER:**

2
3 **(a) and (c)**

4
5 It should be clarified that Tables 8.1 and 8.2 provide information on FBC [Fortis BC
6 (electric)], not FEI [FortisBC Energy Inc.], which is a gas utility.

7
8 Yukon Energy does compare the operational performance to FBC and/or AEY.

9
10 During the review of Yukon Energy's 2021 GRA, the Board noted that Yukon Energy faces
11 some incremental risk with thermal production costs for incremental loads relative to FBC.
12 The Board in its Order 2023-01 awarded 40-basis point risk premium adder for Yukon
13 Energy in recognition of its small size (25 basis point), a further recognition of risks for
14 generation, isolated grid and customer diversity (20 basis point) and less 5 basis points
15 due to the Board's assessment of changes (due to OIC 2021/16). In paragraph 207 of
16 Appendix A to the Board Order 2024-05 Errata, the Board stated that it "continues to find
17 that the ROE for YEC for this proceeding shall continue to be not greater than the ROE
18 determined for FBC before the application of OIC 1995/90. Therefore, YEC's ROE for the
19 2023 and 2024 test years will be 9.15 percent." In paragraph 208, as corrected, the Board
20 further stated that "before the application of OIC 1995/90, YEC's ROE will be 9.65 per cent
21 versus AEY's approved ROE of 9.50 per cent for the 2023-2024 test period. This confirms
22 that YEC relative to AEY is compensated for higher risks."

23
24 Tables 8.1 and 8.2 are provided to confirm the continued application of those findings by
25 the Board. For example, Table 8.1 illustrates that FBC is a much larger utility compared
26 to Yukon Energy [7 times higher revenues, 5 times higher rate base, 60 times more
27 customer base, etc.] and Table 8.2 illustrates that both FBC and AEY purchase the
28 majority of the energy they sell with more diverse customer base, while Yukon Energy is
29 a generation/transmission utility with industrial customers making a notable portion of the
30 sales [for example see the response to YUB-YEC-1-22 that show how the uncertainties
31 around industrial customer could impact Yukon Energy sales/revenues].

32
33 While reviewing the return on equity, Yukon Energy noted that the capitalization in
34 Schedule 4 in Tab 7 for 2025 did not use the deemed 60/40 debt to equity ratio. The
35 correction results in about \$0.08 million reduction in the revenue requirements for the 2025
36 test year. Yukon Energy will reflect this correction in the compliance filing.

1 **(b)**

2
3 Yukon Energy uses best practices within the electric utility industry throughout its
4 business, from operations to capital, from planning to regulatory, etc. Some examples
5 include: the regulatory process where Yukon Energy's revenue requirements are tested
6 by the Board and intervenors, resource planning which is also considered best practice
7 amongst utilities across North America, asset management, the vegetation management
8 plan for transmission lines based on best practices to minimize unscheduled maintenance
9 and effectively manage rights of way, dam safety reviews which aligns with international
10 best practices, etc.

11
12 **(d)**

13
14 Please see UCG-YEC-1-8 Attachment 1.

15
16 **(e)**

17
18 Please see Yukon Energy's response to YUB-YEC-1-25.

19
20 **(f)**

21
22 Some of the generation capacity constraints that Yukon Energy faces are outside of the
23 utility's control. For example, Mayo ice issues that restrict Mayo hydro plant winter outflows
24 and Whitehorse hydro plant winter outflow restrictions to prevent flooding of the Marwell
25 sector in Whitehorse. The fluctuating temperatures due to climate change are adding more
26 pressure, leading to difficulty setting ice downstream of hydro plants, and increasing the
27 risks of flooding and droughts. Yukon Energy is continuously working to mitigate the
28 impact from these issues. For example, the Climate Change Adaptation Plan, Marwell
29 flood prevention design study work, etc.

30
31 Some of the investments to enhance the supply side management opportunities to
32 increase the generation/transmission/distribution capacity from the existing resources
33 include WH 2 Uprate which increased the hydro generation output, proposed WH 1 Uprate
34 [work is expected to start in 2026 and the project is forecast to be in WIP in this GRA],
35 Mayo MH0 Plant Renewal or Replacement [work is expected to start in 2026 and the
36 project is forecast to be in WIP in this GRA], Whitehorse Interconnection, Dawson Voltage

1 Conversion, and Mayo projects, including the Wareham Dam Spillway Project. Please see
2 Tab 5 for the details of the projects.

3

4 **(g)**

5

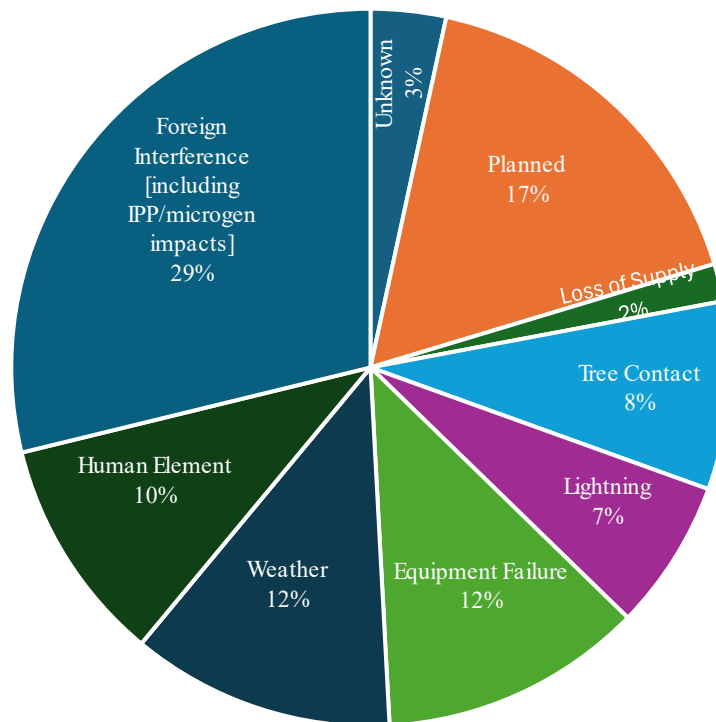
6 Please see the response to NY-YEC-1-20.

Reliability Statistics for 2024

The average electricity customer in the Yukon experienced a lower frequency of outages in the 2024 calendar year compared to 2022 and 2023 [16.2 and 12.3, respectively]; however, the average length and total length of outages were higher in 2024 compared to 2022 and 2023 [8.54 and 11.08, respectively]. Generally, longer outages are the combination of natural events, equipment failures and longer travel times. For example, an outage to a transmission line can take hours for line patrol and PLT travel time.

Average number of outages per YEC customer (SAIFI)	10.43
Average length of outages per YEC customer (CAIDI)	1.16
Total length of outages per YEC customer (SAIDI)	12.14

Source of Outages



SAIFI, SAIDI, and CAIDI:

- SAIFI (System Average Interruption Frequency Index) measures the average number of times a customer experiences an outage per year.
- SAIDI (System Average Interruption Duration Index) measures the average outage duration per customer per year.
- CAIDI (Customer Average Interruption Duration Index) measures the average time it takes to restore service after an outage.

Note: The reliability statistics include AEY and its customer as one customer at the wholesale level.

1 **REFERENCE:** Yukon Energy 2025-27 GRA, p.1-14

2
3 **PREAMBLE:** Yukon Energy outlines rate mitigation strategies, including government
4 funding and partnerships with First Nations.

5
6 **QUESTION:**

7
8 a) Please clarify how Yukon Energy intends to adjust customer rates if government
9 funding is obtained from federal or territorial sources, including any conditions that
10 may be attached to this funding.

11
12 b) Provide a comprehensive list of all mitigation payments made to First Nations for
13 economic and socio-economic impacts, specifying the purpose and amount of
14 each payment.

15
16 c) Indicate whether these costs are assigned to the utility or the ratepayers.

17
18 **ANSWER:**

19
20 **(a)**

21
22 Please see Yukon Energy's response to YUB-YEC-1-10 (e) and (f).

23
24 **(b) and (c)**

25
26 Please see Yukon Energy's responses to YUB-YEC-1-4 and YUB-YEC-1-12.

1 **REFERENCE:** Yukon Energy 2025-27 GRA, p.1-16

2
3 **QUOTE:** "Drivers of rate increases... Other Factors... purchases from power
4 producers."
5

6 **QUESTION:**
7

8 a) Specify how agreements with IPPs are reflected in this application by detailing the
9 types of agreements and impact on rates.
10

11 b) List each purchase from power producers with corresponding details.
12

13 c) Provide a brief cost/benefit summary with ratepayer interest for each agreement
14 (e.g., summary for all wind, summary for all solar, etc.).
15

16 d) List \$ amounts for latest year of Micro-Generation and provide a cost/benefit
17 analysis for ratepayers.
18

19 **ANSWER:**
20

21 **(a) and (c)**
22

23 As detailed in response to YUB-YEC-1-26 (d), there are seven IPPs currently connected
24 to the Yukon Integrated System, including five solar IPPs and two wind IPPs. The IPP
25 supply forecast is based on the LTA contract amounts signed with the IPPs.
26

27 Purchased power from IPP's is forecast at 17.7 GWh for each 2025, 2026 and 2027 test
28 years, compared to 14.3 GWh for 2024 Approved and 2.0 GWh for 2023 Approved. The
29 purchase costs for the IPPs in 2025, 2026 and 2027 assume the contract purchase prices
30 for the existing IPP contracts [based on the latest approved thermal fuel cost at the time
31 of contract, escalated annually as per IPP contracts]. Total IPP purchase power cost is
32 forecast at \$3.397 million for 2025, \$3.431 million for 2026 and \$3.465 million for 2027,
33 compared to \$2.708 million in 2024 Approved. The rate impact from IPP purchase costs
34 in this GRA is about 0.6% out of the 33.73% total rate increase. The breakdown of the
35 rate impact by solar vs wind IPPs would not be meaningful as IPPs were still evolving in
36 2024 [i.e., 2024 test year power purchase cost includes partial year generation from IPPs]
37 and 2025 is the first year when all seven IPPs are in operation for the whole year [two

1 wind IPPs connected to grid in March 2024, one solar in May 2024 and one solar in July
2 2024]. In addition to this, Yukon Energy did not conduct thermal displacement benefits for
3 the IPPs as the IPP deferral account method proposed by Yukon Energy in the 2023/24
4 GRA, which also included long-term average thermal displacement benefits, was rejected
5 by the Board. However, generally, wind IPPs have a higher percentage LTA thermal
6 displacement compared to solar IPPs due to the annual generation distribution.

7
8 **(b)**

9
10 Please see the response to YUB-YEC-1-26 (d).

11
12 **(d)**

13
14 The microgeneration program is administered by the Yukon Government. Yukon Energy
15 does not have the requested information. Please also see the response to YUB-YEC-1-1.

1 **REFERENCE:** Yukon Energy 2025-27 GRA, p.1-18

2
3 **QUOTE:** "Demand Side Management additions-\$1.6million for DSM deferred
4 costs programs related to reducing dependable capacity requirements."
5

6 **QUESTION:**

7
8 a) Provide a cost/benefit analysis for ratepayers on these DSM deferred program
9 additions.
10

11 **ANSWER:**

12
13 **(a)**

14
15 See Tab 5, Appendix 5.2B-2 (page 5.2B-4) which notes that the Demand Side
16 Management (DSM) program introduced in the 2023/24 GRA (DSM Program 2022-2030)
17 will continue during the 2025-27 GRA test years. The relevant cost/ benefit analysis was
18 provided and reviewed and approved by the Yukon Utilities Board during the 2023/24
19 GRA.¹ These conclusions are summarized in Appendix 5.2B-2. The forecast DSM
20 spending in the 2025-27 Application as submitted was consistent with the DSM Program
21 2022-2030. Yukon Energy is currently conducting cost-effectiveness evaluations.

¹ In Board Order 2024-05, the Board's findings were provided in paragraph 291: "Having examined YEC's information and submissions with respect to the Phase I portion of its DSM program, the Board finds that the rationale for the activities and related costs is persuasive. Consequently, the Board finds these costs to be reasonable and they are approved."

1 **REFERENCE: Consultant Costs**

2
3 **QUESTION:**

4
5 a) Provide a summary of consultant costs for 2025 is requested, including the names,
6 work performed, and corresponding dollar amounts.

7
8 b) Provide consultant costs for 2024, with details on names, work performed, and
9 dollar amounts, presented alongside for a comparison to 2025 data.

10
11 c) Forecasted consultant costs for the 2026 and 2027 test years are to be added,
12 listing names and projected amounts.

13
14 **ANSWER:**

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

17
18 The table below provides a summary of consultant costs for 2024 and for 2025 to June
19 30, 2025.

Yukon Energy Corporation
2025-27 General Rate Application
UCG-YEC-1-12

Vendor	2024 Expenditures	2025 Expenditures	Work Performed
Aasman Brand Communications Inc.	\$ 86,310.80	\$ 61,161.14	Communications services
ABSG Consulting Inc. (CAD)	\$ 46,261.85	\$ -	Operations and engineering support
Absorb Software Inc.	\$ -	\$ 5,307.78	HR software support
Allnorth Consultants Limited	\$ 4,747.05	\$ 7,573.13	Resource planning support, Transportation study
AM2 Geotechnical Inc.	\$ -	\$ 4,500.00	Whitehorse Power Centre desktop study
Aperture Consulting Inc.	\$ 128,362.50	\$ 133,416.38	Project management support
Associated Environmental Consultants Inc.	\$ 316,556.20	\$ 5,497.96	Wareham spillway and thermal replacement support
ATCO Electric Yukon	\$ 502,600.26	\$ 133,671.53	Customer service system and project support
AtkinsRealis Canada Inc.	\$ 356,187.15	\$ 125,594.11	Lewes river boat lock and WH4 engineering
AutoGrid System Inc.	\$ 111,751.98	\$ -	DSM support
BBA Engineering Ltd.	\$ 1,208,375.15	\$ 238,726.50	Engineering for thermal replacement and Mayo civil works
Bearwire Solutions	\$ 93,472.67	\$ -	Crane maintenance audit
Believeco Partners Ltd.	\$ 7,290.00	\$ 12,420.00	Funding application support
Brimar and Associates Survey Ltd	\$ 10,140.00	\$ -	Drone scan and site plan creation
CAP Engineering	\$ 116,307.12	\$ 1,976.25	TLR engineering support
CCDI Consulting Inc.	\$ 4,000.00	\$ -	HR consulting services
Charter Telecom	\$ 288,857.70	\$ 301,978.20	IT managed services
Chimax Inc	\$ 21,942.50	\$ -	Pelly River Crossing preliminary engineering
CLEAResult Canada Inc	\$ 147,367.30	\$ 127,200.09	DSM support
Colliers Project Leaders	\$ 7,500.00	\$ -	Thermal business case research
Control Gap Inc.	\$ 47,138.76	\$ 20,745.47	IT/OT security audit
Core Geosciences Services	\$ 15,432.50	\$ 4,100.00	Resource planning support
Crux Trades Ltd	\$ 41,832.08	\$ 22,304.24	Wareham spillway inspection
Current Teknologies Engineering Ltd.	\$ 61,907.98	\$ 3,120.00	Load bank and thermal replacement support
Digital Boundary Group	\$ -	\$ 22,167.00	IT/OT security audit
Dimension Consulting	\$ 14,013.75	\$ 4,856.25	Project management support
Dyggz Marketing Inc.	\$ 50,384.61	\$ 35,137.50	SharePoint support
E.A. Nunn Consulting Ltd.	\$ -	\$ 13,215.39	Health & safety support
EastPoint Engineering Limited	\$ 118,500.00	\$ 83,556.44	Project engineering support
Ecofish Research Ltd.	\$ 372,691.89	\$ 147,073.02	Entrainment study and fish ladder options analysis
Ecofor Consulting Ltd	\$ 16,957.50	\$ -	Wareham spillway support
Econoler	\$ 52,500.00	\$ -	DSM support
eCorall Solutions Inc.	\$ 5,793.75	\$ 675.00	Financial reporting system support
Encore Business Solutions Inc.	\$ 731.25	\$ -	ERP system support
Energy and Environmental Economics, Inc	\$ 27,097.72	\$ 46,312.59	Resource adequacy study
EnFlux Engineering Ltd.	\$ 108,308.45	\$ 72,102.69	MHO penstock, intake engineering
Ensero Solutions Canada Inc.	\$ 1,040,076.36	\$ 375,254.30	WRGS relicensing technical support
Environmental Dynamics Inc.	\$ 556,175.71	\$ 168,260.06	Project engineering support
ERM Consultants Canada Ltd	\$ 141,335.27	\$ -	WRGS relicensing strategic support
Gartner Canada Co	\$ 151,631.00	\$ -	IT strategic support
George & Bell Consulting Inc.	\$ 19,842.04	\$ 4,608.05	Pension administration support
Good Thinking Professional Services	\$ 40,548.95	\$ 23,769.60	WRGS relicensing support
Hammond Safety Solutions	\$ 1,250.00	\$ -	Health & safety support
Hartley, Lyn	\$ 20,142.50	\$ -	Training
Hatch Ltd.	\$ 577,217.16	\$ 247,685.33	BESS and grid modernization support
HR West Consulting, Ltd.	\$ 5,700.00	\$ -	HR support
Intergraph Canada ULC.	\$ 153,912.98	\$ 33,150.00	EAM support
Intergroup Consultants Ltd.	\$ 1,741,131.60	\$ 297,551.63	AGS and MRGS relicensing and GRA support
Interlock Energy Ltd.	\$ 88,302.50	\$ -	LOLE study and fuel options assessment
Jensen Hughes Consulting Canada Ltd.	\$ 56,000.00	\$ -	Fire protection assessment
Karmichael HR Group Ltd.	\$ 5,500.00	\$ 10,650.00	HR consulting services
UpWind Resource Consulting Services	\$ 7,931.25	\$ -	WRGS relicensing support
Kent, Greg	\$ 9,951.25	\$ 5,818.75	TLR permit support
KGS Group	\$ 206,580.36	\$ 42,592.67	Mayo civil engineering
Kirk & Co. Consulting Ltd.	\$ 18,220.00	\$ -	Strategic planning support
Klohn Crippen Berger Ltd.	\$ 218,462.79	\$ 45,558.27	Dam and spillway engineering
Korn Ferry (CA) Ltd.	\$ 13,566.00	\$ 6,384.00	HR consulting services
KPMG LLP (Vancouver)	\$ 65,992.00	\$ -	Project management software research
L2 Consulting, 842879 Yukon Inc	\$ -	\$ 6,705.00	Operations support
LDV Consultants Inc.	\$ 315,695.23	\$ 84,358.22	Mayo B overhaul support
Mahil, Steven	\$ 5,662.50	\$ 1,050.00	Procurement support
Maskwa High Voltage Ltd.	\$ 58,421.50	\$ 13,274.50	Thermal engineering
Maven Consulting Limited	\$ 15,392.00	\$ 412.50	MGS relicensing support

Yukon Energy Corporation
2025-27 General Rate Application
UCG-YEC-1-12

Vendor	2024 Expenditures	2025 Expenditures	Work Performed
Mercer (Canada) Limited	\$ 19,200.00	\$ -	HR consulting services
Metsianorth Consulting	\$ 1,350.00	\$ -	Resource planning support
Midgard Consulting Inc	\$ 55,813.75	\$ -	IPP studies
Morrison Hershfield Limited	\$ 166,127.17	\$ -	AGS relicensing support
Morrison, David	\$ 19,608.42	\$ -	Strategic planning support
Nanook Software Inc.	\$ 120,641.00	\$ 179,661.00	ERP, SQL and EAM support
NELPCo Limited Partnership	\$ 518,158.51	\$ 107,688.48	Mayo rockslide remediation support
Northwest Hydraulic Consultants Ltd.	\$ 197,263.97	\$ 5,265.67	MGS relicensing and AGS MAMP sediment transport services
Paquette, Bethany	\$ 6,024.10	\$ 52,877.50	First aid services
Parhelion Engineering Inc.	\$ 71,337.00	\$ 55,312.96	Wareham spillway engineering
Phasor Engineering Inc.	\$ 49,995.00	\$ 67,392.00	Protection and Control settings, SCADA Design
Power Transformations, LLC	\$ 45,745.03	\$ 2,055.64	RTAC firmware upgrade
Powertech Labs Inc.	\$ -	\$ 46,000.00	Material testing
PR Services Ltd.	\$ 2,443.75	\$ 14.45	Resource planning support
Prophix Software Inc.	\$ 27,200.00	\$ -	Reporting system upgrade
PS Technologies Inc.	\$ 13,200.00	\$ 4,400.00	T&D load growth engineering
R&D Environmental Management Inc.	\$ 4,240.00	\$ -	WRGS relicensing support
Rapid Technical Services Inc.	\$ -	\$ 28,900.00	Gate certification support
RD Energie	\$ 17,379.33	\$ 57,345.81	Gate certification support
Rising Edge Technologies (ENG) Ltd.	\$ 50,747.35	\$ -	Engineering support
S.H.E. Consultanting Inc.	\$ 11,900.00	\$ -	Health and safety COR audit
Sacré-Davey Engineering, Inc.	\$ 39,900.00	\$ -	Maintenance plan update
Sagar, Robert M.	\$ 2,445.50	\$ -	Resource planning support
Sifton Range Environmental Consulting Ltd.	\$ -	\$ 9,300.00	Air quality and noise impact assessment
SLR Consulting (Canada) Ltd.	\$ -	\$ 17,747.48	Faro sound wall modelling
Son Of Mendel Inc.	\$ -	\$ 7,962.50	Electrical maintenance support
Spectrum Security Sound Ltd.	\$ -	\$ 119.97	Security services
Stantec Consulting Ltd.	\$ 2,090,085.50	\$ 376,485.86	Environmental modelling, spillway and boat lock engineering
Stasuk Testing Inspection Ltd	\$ 5,457.00	\$ -	Mayo penstock inspection
Stirling Geoscience Ltd.	\$ 10,400.00	\$ -	WRGS relicensing technical support
Summerhill Group Inc.	\$ 212,786.39	\$ 7,119.54	DSM support
Sylvain Human Resource Services	\$ 24,784.00	\$ -	HR support
Sysoft Computer Consultants Limited	\$ 350.00	\$ 175.00	Software support
Taifa Engineering Ltd.	\$ 64,687.62	\$ -	SCADA support
Tairec Fire Consulting Ltd.	\$ -	\$ 3,520.00	Engineering support
Tatobler Consulting Inc.	\$ 17,000.00	\$ 51,000.00	Business continuity plan support
Valard Construction LP	\$ 10,309.54	\$ -	IPP support
VCURA Canada Incorporated	\$ 13,260.00	\$ 31,000.00	IT managed services
Vector Research	\$ -	\$ 20,545.00	Itron load forecasting
Verdantas LLC	\$ -	\$ 42,470.29	Fish passage options analysis
Veritas Canada Ltd	\$ 3,695.98	\$ -	IT support
Watson Advisors Inc.	\$ 31,500.00	\$ 30,253.13	HR support
Wref's Consulting Inc.	\$ 15,582.11	\$ 3,022.50	Owner's engineer services
WSP Canada Inc.	\$ 239,774.58	\$ 13,254.34	Resource planning and engineering support

(c)

Yukon Energy does not have a forecast of consultant costs for the 2026 and 2027 test years, listing names and amounts.

1 **REFERENCE: Labour pp.3-8,9 and 10 Yukon Energy 2025-27 GRA**

2
3 **PREAMBLE:** Of the total projected increase in labour expenses for 2027 from the
4 2024 approved amount of \$4.446 million, approximately \$3.071 million
5 (69%) is attributed to additional headcount.
6

7 **QUESTION:**

8
9 a) Explain how labour costs are determined and allocated across different categories
10 such as capital, maintenance, and administration purposes.
11

12 b) Describe the process of preparing rate applications for each category of expenses.
13

14 c) Present a concise cost/benefit analysis for the headcount additions, including
15 specific dollar amounts.
16

17 **ANSWER:**

18
19 **(a)**

20
21 Please refer to Yukon Energy's response to YUB-YEC-1-37(a).
22

23 **(b)**

24
25 Please refer to Yukon Energy's response to YUB-YEC-1-37(d).
26

27 **(c)**

28
29 Justification for employee complement additions are provided in Appendix 3.2.

**YUKON UTILITIES BOARD
(YUB)**

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 20

2
3 **ISSUE:** Yukon Energy Challenges

4
5 **QUOTE:** Increasing pressure on the electricity system stemming from population
6 growth, increased use of electricity by homes and businesses, and the
7 connection of distributed energy sources across the territory.
8 (emphasis added)
9

10 **PREAMBLE:** The Board seeks clarification on the above statements.

11
12 **QUESTION:**

- 13
14 a) Please explain the significance of distributed energy sources.
15
16 b) What impact do distributed energy sources have on the electric system and what
17 pressure do these sources put on the electrical system?
18
19 c) On PDF page 18, YEC stated it served approximately 12 percent of Yukon
20 customers.¹ Are these the distributed energy sources putting pressure on the
21 electricity system?
22
23 d) If YEC is including Yukon customers served by AEY, how does that impact YEC
24 as AEY is responsible for the planning of the electricity system for its customers?
25
26 e) Are the distributed energy sources referred to IPPs and micro-generation
27 suppliers? If so, is there currently a pause on such distributed energy sources?
28 Please explain.
29

30 **ANSWER:**

31
32 **(a) to (e)**

33
34 Distributed energy sources in the reference quote are IPPs and microgeneration suppliers
35 on the Yukon Integrated System (YIS), including such suppliers for customers served by

¹ 2700/23,000 = 11.7 per cent.

1 AEY. It is important to note that, although Yukon Energy directly serves a small percentage
2 of the grid customers, it is the primary generator and transmitter of electricity in Yukon,
3 providing approximately 97% of the total electricity generation on the YIS.

4
5 The distributed energy installed as part of the IPP and Micro-Generation programs has a
6 significant impact on the stability and reliability, as well as affordability, of the Yukon grid.
7 No one utility's grid is alike and the maximum permissible penetration level of intermittent
8 renewable energy on power grids depends on numerous factors, including the type of
9 renewable energy sources, seasonal load variations, system frequency response,
10 operational flexibility, and operating reserve requirements. The isolated nature of the
11 Yukon grid makes it even more vulnerable to the impacts of intermittent renewable energy
12 sources.

13
14 Principal factors that limit the safe penetration of intermittent renewables on Yukon's grid
15 include Yukon Energy's ability to maintain frequency and voltage stability, given our small
16 summer load. An adequate supply of hydro or thermal resources must be online to
17 maintain critical system inertia on the system. This inertia is vital to:

- 18
- 19 • Ensure reliability of electricity service. Preventing frequent and widespread
20 outages by having critical power generation units online to respond to changes in
21 grid frequency and voltage when there are changes in energy output from
22 intermittent renewables.
 - 23
 - 24 • Protect electrical equipment, workers and the public. Detecting faults and external
25 contacts, like fallen trees, on the system and automatically turning off sections of
26 the grid to prevent damage to utility and customer equipment, critical damage like
27 forest fires, and injury or death to workers or the public.
 - 28

29 The microgeneration program managed by the Government of Yukon has been extremely
30 successful in terms of subscriptions. Although the program was paused in December
31 2023, the program targets set for 2030 were already met in 2023. The program was
32 oversubscribed, and achieving these targets so rapidly has made achieving our reliability
33 and affordability goals more challenging.

34
35 First, there is a surplus of renewable electricity in the Yukon in the summer. This is
36 because that is when electricity demand is lowest, and our supply of hydroelectricity is
37 highest.

1 Second, solar power generation under the microgeneration and IPP programs are highest
2 during the spring and summer. It provides very little winter energy. The Yukon needs to
3 be laser-focused on investing in projects that increase the supply of winter energy and
4 capacity and decrease peak demands for power in the winter. That's because Yukoners
5 use about three times more electricity in the winter than they do in the summer. As an
6 isolated grid, which means we are not connected to the larger North American grid, we
7 cannot buy winter electricity or sell surplus summer electricity to other places.

8
9 Too much solar power on the electricity system affects our ability to deliver reliable and
10 affordable electricity to Yukoners.

11 12 **Impacts to reliability**

13
14 If there's too many sources of intermittent power on the electricity system, it puts our job
15 of delivering reliable electricity at risk. Our ability to deliver reliable electricity depends on
16 keeping the electricity system in a constant state of balance, where the amount of
17 electricity being generated is always equal to the amount of electricity Yukoners need. Too
18 much solar or wind power in a particular place can cause fluctuations in the supply and
19 demand of energy, resulting in grid instability. This instability reduces reliability and can
20 cause power outages.

21
22 As more solar and wind power have been added to the grid, Yukon Energy's control room
23 has seen more instability on the system.

24
25 Yukon Energy must invest in balancing resources such as energy storage solutions, smart
26 grid technologies, and dependable sources of firm power to manage fluctuations and
27 address issues related to the intermittent renewable energy resources connected to the
28 Yukon grid.

29 30 **Impacts to affordability**

31
32 By its nature, solar and wind power are variable sources of energy. The amount of solar
33 power available quickly drops when a storm rolls in, or the sun goes behind a cloud.
34 Similarly, the amount of wind power generated quickly changes if the wind stops blowing.
35 To account for this and to keep the grid in a constant state of balance, we keep an
36 adequate supply of spinning reserve, or "instantaneous backup power" available. To do
37 this, available hydro units are operated below their capacity and efficiency zone, or thermal

1 assets are run, to supply electricity quickly when the amount of solar power being
2 generated suddenly drops. This causes us to waste hydropower, use fossil fuels,
3 contemplate shutting off renewable electricity generated by independent power producers,
4 and pay for energy we can't use. Ultimately, it costs money to manage intermittent sources
5 of energy on the grid, and these costs need to be recovered from ratepayers.

6
7 In addition to the above, the microgeneration program (solar power only) reduces the
8 overall volume of the energy to distribute the utility cost over. For example, AEY's 2023/24
9 GRA notes that in 2024 the forecast energy that the microgeneration sites put back onto
10 the electricity system was close to 4 GWh. This is extra electricity from microgeneration
11 customers above their own use, i.e., the total energy generated by microgeneration
12 customers could be at least double that or more than 8 GWh. This means Yukon Energy's
13 sales in the summer are reduced by at least 8 GWh while Yukon Energy is still required
14 to build, operate and maintain enough winter capacity to serve all customers, including
15 microgeneration customers, as generally, they don't generate in winter.

16
17 Yukon Energy's Short-Term Action Plan aims to address the issues around reliability of
18 the system, in part due to intermittent renewable resources. Yukon Energy will be
19 increasing thermal resources, as Yukoners need dependable capacity now, and adding
20 critical pieces of infrastructure to our grid, primarily in and around Whitehorse. These
21 projects are necessary to provide the foundation for a modern and adaptable electricity
22 system, one that can integrate more community-based sources of intermittent renewables
23 and emerging technologies as Yukoners' electricity needs continue to evolve. Ongoing
24 investment in infrastructure and winter capacity will be crucial to meeting immediate power
25 needs and supporting renewable energy growth.

1 **REFERENCE: YEC 2025-2027 Application, PDF page 20**

2
3 **ISSUE:** Yukon Energy Challenges

4
5 **QUOTE:** A power system with generating stations that require renewed permits
6 and authorizations at a time when regulatory processes are becoming
7 more complex and costly.

8
9 **QUESTION:**

10
11 a) Please explain how the permitting process for new projects and the relicensing of
12 existing facilities is longer (from the start of the process to final approval), more
13 complex and costly? Please reference the permits and authorizations being
14 referenced

15
16 b) Has YEC looked at an alternative to deferring and amortizing those costs when the
17 process is complete, that is expensing those costs as incurred?

18
19 c) Is there a customer benefit to expensing those costs versus incurring annual
20 Allowance for Funds Used (AFU) charges on the deferred costs?

21
22 d) What analysis has YEC conducted in this regard?

23
24 **ANSWER:**

25
26 **(a)**

27
28 **Hydro Relicensing**

29
30 Over the last 25 years, the three Yukon Energy hydroelectric facilities have provided on
31 average about 90% of the electricity on the Yukon Integrated System. All three of these
32 facilities require Water Use Licences under the Yukon *Waters Act* to authorize Yukon
33 Energy to continue to control water and divert it to turbines for the purpose of hydro power
34 generation.

35
36 In addition to Water Use Licences, Fisheries and Oceans Canada (DFO) has determined
37 that all three of Yukon Energy's hydroelectric facilities also now require Authorizations

1 under the *Fisheries Act* (Canada) to address the death of fish and/or the harmful alteration,
2 disruption or destruction of fish habitat – despite the fact that, at the time Yukon Energy
3 acquired the facilities from the Northern Canada Power Commission in 1987, the
4 Government of Canada provided warranties and representations to the effect that no such
5 Authorizations were required.

6
7 Transport Canada has also determined that, to the extent that Yukon Energy may now
8 plan or propose to alter, rebuild or remove any components of these facilities (for example,
9 for the restoration of the Lewes Control Structure boat lock associated with the Whitehorse
10 Rapids Generating Station, or for the removal and replacement of the Mayo Lake Control
11 Structure associated with the Mayo Generating Station), approvals under the *Canadian*
12 *Navigable Waters Act* may also be required for that purpose, including for temporary works
13 needed to support such activities.

14
15 The processes for renewing Yukon Energy's Water Use Licences and for obtaining any
16 additional required authorizations or approvals under federal legislation have become
17 increasingly more complex and costly in recent years, particularly in light of:

- 18
- 19 • the Final Agreements that have now been entered into between the Governments
20 of Yukon and Canada and each of the Yukon First Nations with Traditional Territory
21 in the project areas for these facilities;¹
22
 - 23 • the establishment, implementation and evolution of the environmental and socio-
24 economic assessment processes required under the *Yukon Environmental and*
25 *Socio-economic Assessment Act* (YESAA) approved by Parliament in 2003, as
26 mandated by Chapter 12 of the Final Agreements; and
27
 - 28 • evolving jurisprudence respecting the duties of the Governments of Yukon and
29 Canada to consult with the First Nations about the relicensing of these facilities
30 and, where appropriate, to accommodate their rights and interests before any
31 renewed Water Use Licence or federal authorization or approval can be issued.

¹ Final Agreements were signed in 1993 with both the Champagne and Aishihik First Nations (CAFN) and the First Nation of Na-Cho Nyäk Dun (FNNND), which have Traditional Territory in the project areas for the Aishihik Generating Station (AGS) and Mayo Generating Station (MGS) respectively. Final Agreements with the three First Nations with Traditional Territory in the project area for the Whitehorse Rapids Generating Station (WRGS) were signed more recently: with Ta'an Kwäch'än Council (TKC) in 2002, and with both Carcross/Tagish First Nation (C/TFN) and Kwanlin Dün First Nation (KDFN) in 2005.

1 While the duty to consult and accommodate is owed by the Governments of Canada and
2 Yukon, as a practical matter, the requirements of YESAA combined with the evolving law
3 in this area now require Yukon Energy to engage directly, meaningfully and extensively
4 with every Yukon First Nation with Traditional Territory in a facility's project area as part
5 of any relicensing process.

6
7 In light of these developments, the relicensing of Yukon Energy hydro facilities now takes
8 years to complete instead of months, requiring extensive engagement with rightsholders
9 and stakeholders in the project area.

10
11 In particular, since the implementation of YESAA in 2005, environmental and socio-
12 economic assessments by the Yukon Environmental and Socio-economic Assessment
13 Board (YESAB) and Decision Documents from Decision Bodies (including, when
14 applicable, the Yukon Government (YG), DFO and/or Transport Canada) are now required
15 before regulators can issue licences or authorizations. In the course of these processes,
16 Decision Bodies are also required to satisfy their common law duty to consult with and
17 accommodate First Nations.

18
19 Meaningful engagement by Yukon Energy with rightsholders in these processes also
20 takes time, especially in the case of legacy facilities like the WRGS, MGS and AGS that
21 were built decades ago without the involvement or consent of First Nations people,
22 resulting in significant negative effects on First Nations people, culture and Traditional
23 Ways of Life. In the context of any current relicensing process, significant time and
24 resources are now needed to meet with First Nation governments and their Citizens to
25 listen and learn about their perspectives and understanding of the ongoing effects of these
26 facilities, to collect and appropriately use Traditional Knowledge – where available – in the
27 assessment of environment and socio-economic effects of the facilities, and to identify
28 meaningful and effective ways to monitor and mitigate effects on a go-forward basis.
29 Appropriate mitigations often also require ongoing collaboration and involvement of First
30 Nation governments in research, planning, implementation and monitoring.

31 32 **Regulatory Timelines**

33
34 Though assessments under YESAA have stipulated timelines, YESAB is on the record in
35 2024 indicating that "...YESAB may not always be able to complete Designated Office
36 Evaluation stages within the timelines outlined in YESAB's Rules... Extensions at all
37 stages of assessment should be expected..." In practice, assessments of Yukon Energy

1 projects can now take more than double the six months that might be expected if stipulated
2 timelines were reliably complied with.

3
4 In addition, it is Yukon Energy's most recent experience that, after an evaluation report
5 has been issued by a YESAB Designated Office, Decision Bodies have been unable to
6 adhere to the 30-day timeline for the issuance of Decision Documents that is prescribed
7 in the regulations under YESAA. Yukon Energy understands that these delays have been
8 driven by evolving jurisprudence respecting governments' duty to consult with First
9 Nations. Following recent YESAB evaluations, it is Yukon Energy's understanding that the
10 evolving law in this area has led Decision Bodies to conclude that significantly more time
11 was needed to complete adequate consultation with First Nations in the project area (up
12 to three or four times the 30-day prescribed period).

13
14 It is also Yukon Energy's recent experience that, after issuance of a Decision Document
15 for a hydro project, the public hearing process before the Water Board can itself be
16 significantly more complex and costly in the current regulatory environment than was
17 typically the case historically. Moreover, when the Water Board ultimately issues a Water
18 Use Licence, the licence may include provisions mandating more extensive ongoing
19 regulatory oversight by the Water Board over the life of the licence, in accordance with the
20 "Review and Approval" process that was added to the Water Board's Rules of Procedure
21 in 2021.

22
23 The most recently completed relicensing process for the Whitehorse Rapids Generating
24 Station (WRGS) provides an illustrative example of the additional complexity and the
25 resulting need for significant additional time to complete regulatory processes, as
26 described above. That relicensing process took more than three years to complete, from
27 the start of pre-submission engagement through the successive completion of the required
28 processes under YESAA and the *Waters Act*.

29
30 Pre-submission engagement for the most recent WRGS relicensing process began in in
31 early 2022 with meetings with the three First Nation governments in the project area
32 (C/TFN, KDFN and TKC). In April 2022, Yukon Energy convened a two-day governance
33 workshop in Carcross, Yukon with participating representatives from TKC, C/TFN, KDFN
34 and YG. The two-day workshop included discussions about project options, outcomes and
35 ways the parties would work together throughout the WRGS relicensing process.

1 After 20 months of intense collaboration on interests and concerns, technical studies,
2 effects assessment and mitigation development (over 70 meetings) Yukon Energy
3 submitted a project proposal to YESAB in early December 2023. The YESAB processes
4 for WRGS then took a total of 477 calendar days or about 16 months (details in YUB-YEC-
5 1-02a Attachment 1) to complete. This included about 13 months for completion of the
6 assessment process by YESAB's Whitehorse Designated Office, which issued a
7 recommendation on January 2, 2025, followed by an additional three months for the
8 issuance of Decision Documents by the Yukon Government, DFO and Transport Canada
9 on April 4 and 7, 2025.

10
11 Yukon Energy submitted its initial application to the Yukon Water Board for a Yukon Water
12 Use Licence in October 2024, while the YESAB process was still ongoing; however, the
13 Water Board could not issue public notice of the application under after the issuance of
14 the Decision Documents. Because of the complexity and resulting delay in the YESAB
15 process, this made it necessary for Yukon Energy to bring a separate application for a
16 short-term 60-day renewal of the WRGS water licence (prior to the expiry of the previous
17 licence on May 31, 2025) in order to provide sufficient time for the Water Board to complete
18 an eight-day public hearing between July 2 and 11, 2025. A 20-year water licence was
19 ultimately issued on July 29, 2025, nearly four months after issuance of the Decision
20 Documents.

21
22 In total, the WRGS relicensing process required more than three years of intense effort to
23 obtain a renewed Water Use Licence. Moreover, Yukon Energy's engagement with DFO
24 to obtain a Fisheries Act Authorization for WRGS is still ongoing.

25
26 The WRGS Decision Documents and the Water Use Licence ultimately issued for WRGS
27 also include requirements for Yukon Energy to implement a fulsome Monitoring and
28 Adaptive Management Plan (MAMP) in collaboration with C/TFN, TKC, KDFN, and where
29 appropriate, the Yukon government, which introduces much greater regulatory complexity
30 (and resulting cost) into the licensing process that was the case historically. The issued
31 Licence also imposed further requirements for Yukon Energy to submit an updated MAMP
32 to the Water Board for Review and Approval in years 5, 10 and 15 of the 20-year licence
33 term, with each of those Review and Approval requirements adding further regulatory
34 complexity, with the potential to trigger additional public hearings before the Water Board.

35
36 Table 01 below further provides additional details regarding the complexity and level of
37 effort required in the recent assessment and water licensing of WRGS.

1 **Table 01: Complexity and Level of Effort in WRGS Relicensing (2023-2025)²**

YEC Whitehorse Rapids Hydroelectric Generating Station - Assessment and Licencing Process			
General			
Assessment and Licensing Overview	Social Licence - Projects involving earthen dams have been under increased scrutiny as they move through assessment and licensing due recent history of geotechnical failures (i.e., Mount Polley mine tailings dam breach, Eagle Gold heap leach failure), making it more challenging for proponents to attain community and stakeholder acceptance and ultimately acquire the social licence to operate the facility.		
	Increased pressure on regulators - This in turn has put increased pressure on the regulators to carry out a more detailed technical review and potentially apply more technical scrutiny to the Project throughout the assessment and licencing process.		
	Multi-disciplinary - A multi-disciplinary team is required to not only support the proponent in improving baseline knowledge, but to also improve operations to prevent similar events from occurring in the future. This multi-disciplinary team is also required to support the proponent during the assessment and licencing process.		
	Regulatory framework - The increasing pressure on regulators has also required the expansion of the regulatory framework to a broader mandate that captures more of the stakeholder interests.		
	Consideration of First Nation Final Agreements - This includes the consideration of the legal requirements in the First Nations Final Agreements on the part of the regulator and the proponent to ensure that the agreements are being upheld in the assessment and relicensing processes.		
	Increased complexity of YESAB and YWUL applications - The added complexities described above result in more advanced and technical applications and more integrated teams being required to move through the assessment and licencing process and attain a long-term WUL licence.		
Whitehorse Rapids Generating Station Relicensing Project Specifics			
Submissions / Documents		Document Count	Total Page Count
YESAB Environmental Assessment	Project Proposal	31	4024
	Information Requests (2 IRs)	9	470
	Technical Submissions	5	279
Yukon Water Use Licence	WUL Application	60	4421
	Information Requests (6 IRs)	37	2067
	Intervention Responses (12 Interventions)	25	516
Additional Documents	Technical Reports - submitted	49	746
	YWB Hearing Preparation (Issues Briefs)	25	290
Project Management - WUL Relicensing Process (April 2024 to July 2025)		Estimated Number	Estimated Total Hours
Team Communications	Regular Meetings	183	183
	As-needed Meetings	400	300
Processes			
YWB Hearing Length	8 business days - this is the longest YWB Hearing since the Yukon Water Board devolved from the federal government		

2

3

4

5

6

7

In the 2023-25 process, Yukon Energy submitted almost 5,000 pages of technical material into the YESAB process and over 7,000 pages into the water licensing process. In addition to the substantial initial filings, more than 2,500 pages of additional material were required to respond to information requests from assessors and regulators during the process.

² Meetings listed under "Team Communications" indicate a level of effort from the 'internal' team of Yukon Energy, Ensero and technical sub-consultants. They do not include Technical Working Group (TWG), Senior Officials Group (SOG) or negotiator meetings with KDFN, TKC, C/TFN and YG, which were significant and went above and beyond what is listed in the table.

1 This material was developed using teams of expert technical consultants with extensive
2 experience with Yukon assessment and regulatory processes. Yukon Energy consulting
3 teams included: biologists, hydrologists, hydrogeomorphologists, archaeologists, civil
4 engineers, and experts in traditional knowledge, land use, socioeconomics, effects
5 assessment, climate change and engagement.

6
7 In contrast to the most recent WRGS relicensing process, to relicense WRGS in 2000,
8 Yukon Energy submitted a simple form and less than twenty pages of information.

9
10 The currently ongoing relicensing process for Mayo Generating Station (MGS) provides
11 another illustrative example of the increased complexity and cost of current relicensing
12 processes.

13
14 Pre-submission activities for the MGS relicensing began in January 2023. After 19 months
15 of field studies, collaboration, engagement, assessment and mitigation development with
16 FNNND and Yukon Government, Yukon Energy submitted a YESAA project proposal in
17 July 2024. The YESAA assessment processes took nine months until April 2025, and as
18 of August 26, 2025, four months after the issuance of a recommendation by YESAB's
19 Mayo Designated Office, Decision Documents still have not been issued. A Yukon Water
20 Use Licence application was submitted in March 2025, while the YESAB process was
21 ongoing, but that process has been paused until Decision Documents are issued. The
22 temporal scope of the assessment and proposed term of the water licence is five years.

23
24 As for the Aishihik Generating Station (AGS), the relicensing process for the 17-year
25 Water Use Licence issued in 2002 under the former *Yukon Waters Act* (Canada) began
26 in 2015. After 40 months of collaboration with Champagne and Aishihik First Nation
27 (CAFN) and Yukon Government, field studies, engagement, effects assessment and
28 development of new mitigation/monitoring, a project proposal was submitted to YESAB.
29 The assessment was completed, and Decision Documents were issued within eight
30 months – timelines approaching those set in Rules and Regulations – however, this was
31 only for a three-year licence to enable Yukon Energy to proceed immediately with planning
32 for subsequent assessment and licensing for a longer-term licence.

33
34 In 2020, planning was limited to seven months for a proposed 25-year licence for AGS;
35 however, the YESAA assessment processes required approximately 15 months and
36 resulted in YESAB's Haines Junction Designated Office unilaterally reducing the temporal
37 scope of the licence to five years. As a result, the Water Board was only able to issue a

1 five-year licence in December 2022, which will expire on December 31, 2027 – thereby
2 requiring completion of another AGS relicensing process over the next two years.

3
4 A result of the more complex assessment and regulatory processes are licences that have
5 more extensive requirements. For example, the 2000 WRGS water licence for 25 years
6 had 26 terms and conditions and the 2025 water licence for 20 years has over 80 terms
7 and conditions, several with multiple sub-conditions. The 2025 water licence requires
8 broader reporting requirements and, as noted above, it provides the Yukon Water Board
9 with a “review and approve” process every five years during the term of the licence. This
10 “review and approve” process has not been defined or implemented previously.

11
12 While the examples listed above involve the most recent relicensing processes for Yukon
13 Energy’s three hydroelectric generating stations, it is also important to recognize that
14 increasing regulatory complexity is not confined to hydro projects. It also extends to other
15 projects that are subject to environmental and socio-economic assessment under YESAA,
16 including thermal electrical generation projects requiring Air Emission Permits.

17
18 In that regard, it should be noted that YESAA defines two paths for assessments:
19 Designated Office Evaluations for smaller, simpler projects that are expected to take less
20 than six months; and Executive Committee Screenings for larger, more complicated
21 projects more likely to have significant effects that are expected to take at least 18 months.

22
23 Thermal electrical generation projects adding more than 4.9 MW of production require the
24 higher level of assessment under YESAA – a Screening. Practically speaking, this means
25 that forecasted Yukon load growth exceeds the rate at which Yukon Energy can
26 incrementally assess and permit the required generation.

27
28 In an effort to mitigate this risk on a go-forward basis, Yukon Energy has adopted the
29 approach used for Callison by assessing and permitting more capacity than immediately
30 required. At Callison, Yukon Energy assessed and permitted 15.5 MW of generation and
31 installed 6.5 MW. This approach allows for YESAB and Decision Bodies to evaluate the
32 effects and make recommendations based on the maximum level of generation that Yukon
33 Energy forecasts will eventually be required based on available information at the time the
34 facility is first built. This approach is expected to provide opportunities for more efficient
35 and expedited permitting as generation assets are added to the facility in response to load
36 growth.

1 Assessment and regulatory process changes introduce uncertainty, complexity and cost
2 for Yukon Energy for all projects subject to assessment. An example of this is YESAB's
3 introduction of a new "Pre-Submission Engagement" process for Executive Committee
4 Screenings. The result is months of additional process and engagement prior to being
5 able to submit a project proposal and start the assessment process.

6
7 Federally, successive federal governments have also changed the scope and mandate of
8 the *Fisheries Act*, either through legislative amendments or through their interpretation
9 and application of existing legislative provisions. Efforts by Fisheries and Oceans Canada
10 to bring hundreds of legacy hydro facilities across Canada without FAAs into compliance
11 with the *Fisheries Act* – as currently interpreted by DFO – are challenging for Yukon
12 Energy as they are for other utilities and facilities across the country.

13
14 With respect to thermal generation, Air Emissions Permits regulate capacity and
15 operations at all Yukon Energy thermal generation facilities. Historically, Yukon Energy
16 has differentiated between operational and emergency capacity. The latter would be used
17 infrequently during the year to meet winter peak demand and protect the public from risks
18 to their health and safety. However, as noted both in the 2023/2024 GRA and in Appendix
19 3.1 of the current 2025-2027 Application (PDF pages 113-114), Yukon Energy has
20 recently received direction from Yukon Government that total generation capacity should
21 be permitted at each thermal facility, and it has been completing the required assessments
22 and permitting to achieve that objective for all existing thermal facilities. All of these
23 processes are lengthy and add additional regulatory complexity (and resulting cost).

24
25 In conclusion, Yukon assessment and permitting processes now take years to complete
26 for both new and existing facilities. These processes provide opportunities for participation
27 by rightsholders, including First Nations, territorial and federal governments, special
28 interest groups and the public. Expectations continue to increase with respect to breadth
29 and detail of information, modelling and prediction particularly for climate change. Process
30 change and uncertainty create challenges. All of these factors increase the length,
31 complexity and costs associated with assessment and permitting of Yukon Energy's
32 facilities and operations.

33
34 **(b)**

35
36 Yes, Yukon Energy has looked at expensing licensing costs as incurred.

1 **(c)**

2
3 There are customer benefits and disadvantages to expensing these costs as incurred.
4 Customer benefits include:

- 5
- 6 • Avoidance of AFUDC charges;
 - 7 • Rate increases occurring sooner and more frequently; and
 - 8 • Once licence secured, no ongoing costs in rates.
- 9

10 Disadvantages to the customer include:

- 11
- 12 • Considerable rate instability/fluctuations;
 - 13 • Rate increases occurring sooner and do not match the period of the benefit,
14 resulting in current customers paying for costs relating to benefits that occur in the
15 future (the period of the licence). For example, costs for a twenty-year licence
16 would be charged to current ratepayers rather than ratepayers over the twenty-
17 year period in which the licence is effective; and
 - 18 • Initial rate increases would be higher and would not equal out until the end of the
19 licence period.
- 20

21 **(d)**

22
23 Given the benefits and disadvantages listed in part (c), there is no reasonable basis to
24 expense the costs as incurred. In addition, licences meet the International Financial
25 Reporting Standards (IFRS) definition of intangible assets. Consistent with IFRS, Yukon
26 Energy records the asset at cost including AFUDC, amortization begins when the licence
27 period commences and is recognized as an expense on a straight-line basis over the
28 estimate use life (the term of the licence).

YEC Whitehorse Rapids Hydroelectric Generating Station (2023-0167)
YESAB Designated Office Evaluation Timelines vs. Whitehorse Designated Office WRGS Timelines

Evaluation Stage		DO Evaluation Timelines (min – max)	Whitehorse DO WRGS Timeline	Additional Time	Total Calendar Days	Key Dates
ADEQUACY	Adequacy Review	8 – 29 days	23 days ¹	- 6 days	46 days	Project Proposal Submitted: December 14, 2023
	Review IR Response	Up to 10 days	8 days	- 2 days		Adequacy Review Begun: December 18, 2023
EVALUATION	Seeking Views and Information	14 – 35 days	109 days	+ 74 days	248 days	Information Request # 1: January 16, 2024
	Review Information	Up to 3 days	65 days	+ 62 days		Proponent Response: January 19, 2024
	Information Request	–	–	–		Proposal Deemed Adequate: January 29, 2024
	Information Request Response ²	28 days - 1 year	42 days (YEC time)	–		Public Comment Begun: January 29, 2024
	Review Information	Up to 3 days	8 days	+ 5 days		Public Comment Period Extended: February 1, February 27, April 23, and May 3, 2024
	Additional Seeking Views and Information	10 – 35 days	10 days	–		Public Comment Period Closed: May 17, 2024
	Review Information	Up to 3 days	3	–		Review Information: May 21 - July 24, 2024
						Information Request # 2 Issued: July 24, 2024
RECOMMENDATION		Prepare Recommendation	14 – 35 days	91 days	91 days	Information Request Response: July 24 - Sept 4, 2024
		Total	62 - 150 days ⁴	+ 197 days ⁵	385 days	Review Information: September 5 - September 16, 2024
						Public Comment Begun: September 17 - September 26, 2024
						Review Information: September 30 - October 3
						October 3 - January 2, 2025
						Total process (Dec 14, 2023 to January 2, 2025)
Decision Body Stage		DB Timelines	YG-Cdn WRGS Timeline	Additional Time		
DECISION DOCUMENT	Issue Decision Document	Up to 30 days	85 days	+ 55 days	91 days	January 3 - April 4 ⁶ , 2025
	Total	Up to 30 days	85 days	+ 55 days	91 days	Total process (January 3 to April 4, 2025)
		Combined Timelines	WRGS Combined Timelines	Additional Time		
		Total	Up to 180 days ⁴	+ 252 days	477 days	Total process (December 14, 2023 to April 4, 2025)

¹ First 8 days does not include weekends and holidays

² Up to 28 days for the proponent to provide information or advise when it will be submitted within 1 year of evaluation commencing

⁴ Standard YESAB timeline estimate (does not include proponent's time for response to IRs, or multiple IRs)

⁵ Includes time taken by YEC to respond to IR#1 (3 days) and IR#2 (42 days) which is not included in YESAB DO Timelines.

⁶ Federal DBs state they received ER on Jan 7 due to update by DO. This is a difference of 4 days which would be shifted to the "Prepare Recommendation" stage, but not change the overall timelines and difference.

As per the "Rules for Evaluations Conducted by Designated Offices":

(a) if the time for doing an act falls or expires on a Saturday, Sunday or holiday, the time is extended to the next day that is not a Saturday, Sunday or holiday;

(b) if a period of time is expressed as a number of "days", the first day is excluded and the last day included; and

(c) if the period for doing an act is less than 10 days, Saturdays, Sundays, and holidays shall not be included in the computation of time.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 20

2
3 **ISSUE:** Yukon Energy Challenges

4
5 **QUOTE:** Increased competition for government funding and grants

6
7 **PREAMBLE:** The Board seeks clarification on the above statement

8
9 **QUESTION:**

10
11 a) What government funding and grants have impacted the revenue requirement in
12 this GRA?

13
14 b) What funding was available in previous GRAs that is not available for this GRA?

15
16 **ANSWER:**

17
18 **(a)**

19
20 This Application for the 2025-2027 test year includes \$16.5 million in government grants
21 towards the Battery Energy Storage System (BESS) project, which is included as an offset
22 to the rate base in 2026.

23
24 **(b)**

25
26 There are no general contribution streams that are provided every year. The previous
27 GRAs included contributions towards specific projects. For example, the 2017/18 GRA
28 included \$22.4 million in government contributions for the LNG project and other deferred
29 costs as an offset to the rate base. The 2021 GRA included approximately \$22.7 million
30 contributions towards Mayo to McQuesten Transmission Line project. There were no
31 government contributions included for the 2023 and 2024 test years in the 2023/24 GRA
32 other than Demand Side Management project contributions totaling slightly over \$0.800
33 million.

1 **REFERENCE: YEC 2025-2027 Application, PDF page 22**

2
3 **QUESTION:**

4
5 a) What does YEC mean by “reducing socio-economic impacts of existing power
6 production”?

7
8 b) How does YEC plan to reduce those socio-economic impacts?
9

10 **ANSWER:**

11
12 **(a) and (b)**

13
14 Yukon Energy outlined its commitment to working with First Nations with the release of its
15 Road Map and Chapter 1: Building a Resilient and Renewable Energy Future in April
16 2025. There are opportunities for First Nations collaboration and investment in a wide
17 range of projects. Yukon Energy is committed to fostering strong partnerships at every
18 level of its business, and sourcing locally, when economical, to ensure shared growth and
19 success.
20

21 As a public utility, Yukon Energy strives to fulfill commitments as outlined in Chapter 22 of
22 the Umbrella Final Agreement including economic development, employment,
23 procurement and investment, amongst others. Yukon Energy acknowledges that the
24 historical development of its hydro facilities has had lasting effects on both the
25 environment and the traditional use of the land by Yukon First Nations. Today, Yukon
26 Energy is actively conducting studies, adjusting operations, and implementing mitigation
27 strategies to reduce the environmental and socio-economic impacts of these existing
28 facilities. Through Yukon Energy’s work to relicence the hydro facilities in Mayo,
29 Whitehorse and Aishihik, past agreements with First Nations will be drawn on as a
30 powerful example of the positive outcomes that can be achieved through meaningful
31 partnerships and collaboration.
32

33 Building a reliable and robust grid means taking a new approach – one that considers the
34 needs and values of the communities Yukon Energy serves. Relationships with First
35 Nations governments, communities and businesses is vital to success.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 23, lines 11-15.

2
3 **ISSUE:** Yukon Energy's Short-Term Action Plan

4
5 **QUOTE:** Battery Energy Storage System

6
7 **PREAMBLE:** Additional explanation is needed.

8
9 **QUESTION:**

- 10
11 a) Does the conclusion regarding the number of rented diesels required for 2035
12 take into account the commissioning of the BESS project? Please explain.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Yes, the Battery Energy Storage System (BESS) is included as dependable capacity
19 starting from the 2026/27 winter as indicated in footnote 23 on page 2-16 and Table 2.3
20 of Tab 2.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 23, Footnote 3

2
3 **ISSUE:** Yukon Energy's Short-Term Action Plan

4
5 **QUOTE:** Does not include rental diesels and IPPs.

6
7 **PREAMBLE:** Additional explanation is needed.

8
9 **QUESTION:**

10
11 a) Please explain why the capacity of the Yukon's main electricity system does not
12 include rental diesels.

13
14 b) Please explain why IPPs are excluded.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The diesel rentals are included as dependable capacity, as shown on pdf page 54 of the
21 Application [page 2-14 in Tab 2]. However, the diesel rentals are not permanent. They are
22 considered as a residual option and a short-term solution, to the extent that the
23 combination of other feasible options to be implemented by Yukon Energy would be
24 insufficient to meet dependable capacity. The number of rentals changes as the peak
25 changes and/or new permanent resource options are developed. Therefore, Table 2.3
26 does not include diesel rentals.

27
28 **(b)**

29
30 The Yukon Integrated System (YIS) currently includes seven IPPs, including five solar
31 IPPs and two wind IPPs. The IPPs are intermittent resources, such as solar and wind,
32 which are non-dispatchable or dependable because they can only generate electricity
33 while their energy source is available. Therefore, the currently connected IPPs are not
34 included as a dependable capacity.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 23, Footnote 4

2
3 **ISSUE:** Yukon Energy's Short-Term Action Plan

4
5 **QUOTE:** Adjustments reflect impact of lower winter water levels, downstream
6 flow restrictions required to prevent flooding, and Forced Outage Rate
7 reductions for effective load carrying capacity. (emphasis added)

8
9 **PREAMBLE:** The Board seeks clarification on the above statement.

10
11 **QUESTION:**

12
13 a) Please explain why dependable capacity for winter 2027/28 is adjusted for forced
14 outage rate reductions for effective load carrying capacity.

15
16 b) Would the Forced Outage Rate reductions apply in summer? Please explain.

17
18 **ANSWER:**

19
20 **(a)**

21
22 In its Order 2024-5 (Appendix A, paragraph 137), the Board directed Yukon Energy to
23 provide "a strong industry based and accepted approach on what the manufacturers
24 accept as criteria and evidence for uprating thermal generation units."

25
26 Maximum rated winter capacity for thermal units continues to be the maximum generation
27 output that each resource can produce when load tested at ambient temperatures during
28 the winter.

29
30 However, starting in winter 2024/25 for this GRA, Yukon Energy has adopted an industry
31 standard approach for determining the winter dependable capacity of its generation
32 resources (i.e., the maximum generation output that a resource can reliably provide during
33 a period of greatest demand in the winter), including both thermal and hydro generation
34 resources. Winter dependable capacity of a generation resource is calculated by
35 multiplying its maximum rated winter capacity by its effective load carrying capacity
36 (ELCC). Adoption of ELCC reduces the resource's dependable capacity to reflect

1 expected reliability problems or unplanned outage events when the resource would not be
2 available for generation during peak periods.

3
4 For conventional thermal generators, the industry standard for determining capacity
5 contribution, or ELCC, has historically been calculated with forced outage data. The
6 Independent Electricity System Operator in Ontario, and consistent with the IEEE
7 Standard 762-2023, determines the average Forced Outage Rate (FOR) of a generator
8 based on five years of dataset. Consistent with this industry standard, Yukon Energy
9 determines the weighted average FOR of each Yukon Energy owned diesel and liquefied
10 natural gas generating station based on forced outage data from the past five years.

11
12 **(b)**

13
14 Forced outage rates of generation resources also apply in the summer. Yukon Energy
15 determines capacity and energy needs during different periods of the year, including
16 summer, for reasons including:

- 17
18 1. To ensure adequate generation capacity is available when scheduling
19 maintenance activities and in the event of unplanned outages; and
20
21 2. To ensure sufficient energy can be supplied from generation resources during
22 periods with lower water levels and flow restrictions.

23
24 However, the reductions for effective load carrying capacity in the summer do not govern
25 the capacity planning criteria because winter demand is higher than demand in the
26 summer and ultimately, the winter dependable capacity governs the capacity planning
27 criteria.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 4 and 23

2
3 **ISSUE:** Diesel rentals/growth in demand

4
5 **QUOTE:** During the Winter of 2024/2025, Yukon Energy rented 22 diesel units
6 (nearly 40 megawatts) to fill the power gap and located those units in
7 Whitehorse, Faro and Mayo. Based on current forecasts, without any
8 new dependable generation, by 2035 Yukon Energy will need double
9 the number of rented diesel units during the winter to meet peak
10 demands for power and protect against prolonged outages during an
11 emergency.

12
13 **PREAMBLE:** Further explanation is needed

14
15 **QUESTION:**

- 16
17 a) If YEC is forecasting a shortfall of rented diesel units by 2035, isn't this a long-term
18 problem? Please explain.
19
20 b) If YEC is forecasting the rental of diesel units by 2035, should a permanent solution
21 be found and applied? Please explain.
22
23 c) PDF page 4 of the application states that by 2035 demand is forecast to increase
24 by 50 percent relative to the demand in 2020. What is the increase in demand for
25 2025 relative to 2020?
26
27 d) Given the projected increase in demand to 2030, does the distribution
28 infrastructure exist to meet the expected growth in demand? If the infrastructure
29 does not exist, does this affect the accuracy of the forecast? Please explain. Is it
30 realistic that the infrastructure can be developed and implemented for 2030?
31 Please explain.

32
33 **ANSWER:**

34
35 **(a) and (b)**

36
37 The referenced quote simply highlights updated forecast growth in required dependable
38 capacity in winter by 2035 and how, "without any new dependable generation", this would

1 require double the number of diesel units rented in winter 2023/24. The quote was not
2 forecasting anything as regards to 2035 diesel rental units.

3
4 The context for the quote is reviewed below, including the evolution in Yukon Energy's
5 planning for a permanent solution to reduce reliance on diesel rentals.

6
7 Yukon Energy typically carries out resource plan updates in approximate five-year
8 intervals to assess 10 to 20-year grid forecast generation requirements and supply
9 options. Since the 2006 Resource Plan, these periodic updates have reassessed forecast
10 dependable capacity requirements and supply options and provided updated resource
11 plans for meeting Yukon Integrated System (YIS) forecast capacity and energy
12 requirements.

13
14 The resource planning to date did not identify diesel rentals as something to be proposed
15 on its own as a long-term dependable capacity resource option. Rather, Yukon Energy's
16 diesel rental implementation from the winter of 2017/18 up to the current GRA has been
17 informed cumulatively by forecasting non-industrial peak demands for power and other
18 internal analysis relating to the assessment, selection, development and commissioning
19 of other, non-rental dependable capacity resource options. In that context, Yukon Energy
20 has considered diesel rentals as a residual option, to the extent that the combination of
21 other feasible options to be implemented would be insufficient to meet dependable
22 capacity shortfalls without being supplemented by diesel rentals.

23
24 Information from prior Yukon Energy regulatory proceedings, including the BESS, the Atlin
25 EPA, 2021 GRA, 2023/24 GRA as well as from the current GRA proceeding, demonstrates
26 how the diesel rental option was identified as the only feasible way to address forecast
27 dependable capacity shortfalls on a temporary basis pending the development and
28 commissioning of new permanent dependable capacity and/or related DSM measures to
29 meet dependable capacity requirements. Development and commissioning of new
30 permanent dependable capacity has been considered by Yukon Energy for many years:

- 31
32 • After completion of the 2017-18 GRA proceeding, YEC continued to be focused
33 on its initial planning and feasibility assessment for the 20 MW diesel plant project
34 contemplated by the 2016 Resource Plan. In 2019, however, after completing
35 initial option assessments, planning and engagement activities for the 20 MW
36 thermal plant, Yukon Energy's Board of Directors decided not to proceed with the
37 20 MW thermal plant project and to proceed instead with the updated resource
38 plan as would subsequently be detailed in the 10-Year Renewable Electricity Plan

1 that was first presented in January 2020, and which included replacing 12.5 MW
2 of diesel capacity which had or was planned to reach end-of-life, the grid-scale
3 battery (BESS) and Atlin Hydro Expansion projects, capacity DSM, and the Moon
4 Lake Pump Storage project as permanent dependable capacity options.
5

- 6 • The 2021 GRA, BESS and Atlin EPA proceedings reviewed then available
7 information and analysis on dependable capacity non-industrial peak MW
8 requirements, committed and planned resources, and forecast diesel rental use to
9 address forecast N-1 dependable capacity shortfalls prior to then-planned
10 installation of the phase 1 Moon Lake Pump Storage Project's 35 MW of
11 dependable capacity by winter 2028/29, followed by phase 2's additional 10 MW
12 in winter 2031/32.
13
- 14 • As was reported during the 2023/24 GRA, Yukon Energy started to revisit the
15 resource options included in the 10-Year Renewable Electricity Plan to take into
16 account ongoing changes, including delays expected in development of the Atlin
17 Hydro Expansion and the fact that Yukon Energy did not have full support from
18 First Nation communities to advance the Moon Lake Pumped Storage Project at
19 this time.
20
- 21 • As reported in Appendix 3.1 of the current 2025-2027 Application, on April 8, 2025,
22 Yukon Energy released two new documents: *Building a Resilient and Renewable*
23 *Energy Future: Yukon Energy's Road Map to 2050* and *Chapter 1: A Reliable and*
24 *Robust Grid 2025-2030*, a five-year strategic plan.
25
 - 26 ○ As a pathway to a net-zero by 2050, Yukon Energy's new plans have
27 identified a three-phase pathway: (1) Building a reliable and robust grid; (2)
28 Creating a modern and flexible grid; and (3) Transitioning to a resilient and
29 clean grid.
30
 - 31 ○ The Short-Term Actions focusing on 2025-2030, as part of the upcoming
32 Resource Plan, identify plans to build a reliable and robust grid over the
33 next five years. The goal is to increase the reliability and stability of the grid
34 to meet growing demands for power and such that intermittent renewables
35 can be integrated without impacting grid stability as a pathway towards net-
36 zero.

- 1 ○ The new thermal resources are the fastest and most reliable option to
2 replace the capacity provided by the rental diesel generating units, meet
3 on a timely basis the increased demands from load growth, and provide
4 reliable backup capacity for proposed renewable resources. Therefore,
5 Yukon Energy is working to develop new Power Centres - the Whitehorse
6 Power Expansion Project (see Application Appendix 5.4A) - and develop
7 new thermal capacity for planned in-service before winter of 2027/28.
8

9 After filing the current GRA, Yukon Energy in June 2025 submitted the Whitehorse Power
10 Centres Project (WPCP) Description (included as Whitehorse Power Expansion Project in
11 the Application) to the Yukon Economic and Socio-Economic Assessment Board to initiate
12 the pre-submission process for an Executive Level Screening under the Yukon Economic
13 and Socio-Economic Assessment Act. The WPCP includes assessment for construction
14 of up to three generation sites near the Whitehorse area: One south power centre for up
15 to 30 megawatts and one north power centre for up to 60 megawatts, plus an additional
16 north power centre for up to 60 megawatts to be assessed as a contingency option.
17

18 Please see YUB-YEC-1-8 (a-b) Attachment 1 for a summary information update on the
19 WPCP and the forecast permanent dependable capacity shortfalls being addressed by
20 Yukon Energy on the YIS, including the incremental capacity shortfall as identified in
21 response to YUB-YEC-1-30 (b).
22

23 Note also that, going forward, Yukon Energy's forecast dependable capacity shortfalls
24 reflect the modified approach it has adopted for determining winter generation capacity of
25 its generation resources in response to the Board's direction in paragraph 137 of Order
26 2024-5 (Appendix A) as described in Tab 2, Section 2.4 of the Application (PDF page 52).
27

28 **(c)**
29

30 The forecast increase in non-industrial peak demand from 2020 to 2025 to date is about
31 18%.
32

33 **(d)**
34

35 Yukon Energy, together with ATCO Electric Yukon (AEY), will continuously assess the
36 condition and reliability of the distribution infrastructure that each utility respectively owns
37 and work on upgrading said distribution infrastructure as needed to meet the expected
38 growth in demand.

1 For example, please see section 5.1A-7 in Tab 5 for the Dawson City Voltage Conversion
2 project to upgrade the Dawson distribution system to improve reliability, stability, and
3 ensure appropriate distribution capacity. Also, AEY in its 2023/24 GRA stated that “since
4 the last GRA there has been significant load growth in the Yukon (approximately 40
5 percent increase since 2014), as a result of the rapidly increasing population. This growth
6 has led to the need for AEY’s capital program to keep up with the demand, as can be seen
7 in the steadily increasing capital expenditures. This increase was not only required to
8 maintain safe and reliable service but also to strengthen and grow the power system as
9 the demand continues to rise.”

Whitehorse Power Centres Project Updated Information

The role of diesel power generation in the Yukon

Although the share of the electricity generated from diesel is small, it has played and continues to play an important role in the Yukon Integrated System (YIS) electricity system. As an isolated power grid, diesel is primarily used to generate electricity when there is not enough hydro or LNG resources to meet demand, to protect against extended outages during emergencies, to restore power outages quickly, and to keep the lights on when other generating units or transmission lines are out for service.

Most recently, diesel has also been used as spinning reserve – a back-up cushion – to stabilize the power system from fluctuations caused by intermittent energy resources such as solar and wind, and to prevent power outages when the wind stops blowing or clouds roll in covering solar panels.

The role of rental diesels

During the winter of 2025/26, Yukon Energy will rent 22 diesel units in Whitehorse, Faro, and Mayo to address a YIS shortfall in permanent dependable winter capacity. Since winter 2017/18, Yukon Energy has rented diesel generators each winter to fill the gap between what Yukon homes and commercial (non-industrial) businesses were expected to need during winter peaks and the amount of winter capacity Yukon Energy could generate at a single point in time if its largest power plant – the Aishihik hydro facility – were out of service due to the issues with the plant or the transmission line that connects hydro power to the YIS. This is commonly known as the N-1 planning criteria.

To date, Yukon Energy's resource planning has not identified diesel rentals as something to be proposed on its own as a long-term dependable capacity resource option. Rather, diesel rentals were consistently determined each winter since winter 2017/18 and up to the current GRA to supply dependable capacity needs until selected permanent dependable resources would be in-service. Throughout these earlier years, the record shows Yukon Energy's ongoing assessment, selection, and (in at least some instances) development and commissioning of other, non-rental dependable capacity resource options (i.e., the 20 MW diesel plant, grid-scale battery (BESS), Atlin hydro expansion project, Moon Lake pumped storage, 16.5 MW diesel replacement project). However, for reasons including construction delays, lack of funding and/or social support, the commissioning of these planned permanent projects has either been delayed, cancelled or put on hold.

In that context, Yukon Energy has considered diesel rentals as a residual option, to the extent that the combination of other feasible near-term options available to be implemented would be insufficient to meet dependable capacity shortfalls without being supplemented by diesel rentals.

The urgent need for more winter power

Currently, during the winter months, Yukon homes and businesses connected to the main grid (excluding mines) use about 80% of the electricity that is available at a single point in time. Simply put, demands for electricity in the Yukon are increasing faster than firm sources of winter renewable electricity can be built. The Yukon's population is growing and, with it, the demand for electricity. As Yukoners continue to transition away from fossil fuels for heating and transportation, that electricity demand will only rise. By 2035, YIS non-industrial peak demands for power as updated are expected to be at least 50% higher than they were in 2020. As an isolated electricity system that is not connected to another province or territory, this leaves the Yukon vulnerable to extreme weather conditions, emergencies, and droughts.

In the next five years, Yukon Energy will focus on increasing the supply of dependable winter power to meet growing demands and build a stronger, more resilient power system. This work will meet the needs of Yukoners today and set the Yukon up for the next generation of community renewable energy projects. Most importantly, it will ensure that Yukon Energy can provide an adequate and dependable supply of electricity in the winter, and a robust transmission and distribution system to deliver that electricity to Yukoners.

Demand for power is expected to grow the fastest in the Yukon's major load centre – Whitehorse. As a result, Yukon Energy will be increasing thermal resources in the short term and adding critical pieces of infrastructure to our grid, primarily in and around Whitehorse, as Yukoners need dependable capacity now. Thermal resources are the fastest and most cost-effective solution to meet current needs, and Yukon Energy is firmly committed to providing Yukoners with electricity they can count on today to fuel their homes, businesses, hobbies, and interests. At the same time, Yukon Energy is championing renewables by reinvesting in existing hydro resources and strengthening the grid to support the next generation of community renewables.

The Whitehorse Power Centres Project

Yukon Energy will build two new thermal power centres and one new substation in the Whitehorse area to meet dependable capacity electricity needs until 2040. A site for a potential third thermal power centre, to be used as contingency, will also be assessed. Collectively, these four sites and each of their respective transmission connections to the Yukon grid make up the scope of this project.

The new Whitehorse Power Centres will serve three main purposes:

1. Increase the size of the Yukon's electricity system and provide additional sources of dependable capacity that Yukoners can rely on during the winter to keep homes warm and lights lit on the coldest of days, in drought years, and when intermittent renewable resources are not available.
2. Reduce Yukon Energy's reliance on rental diesels. Renting diesel units each winter, while cost-effective over a short period of time, comes with risks such as limited supply chain, lower reliability, and reliance on an external contractor for maintenance. The capacity installed at these new power centres will account for the capacity that rental diesels provide us each winter, plus additional capacity needed to address growing demands for power.
3. Provide the substation and transmission infrastructure needed to support the increased power Yukon Energy is expecting in each of these regions, and the potential for additional batteries to enhance grid stability and flexibility as more intermittent renewable resources are added to the grid.

These Whitehorse Power Centres are needed to meet the needs of Yukoners, now and in the long run. While it might seem counterintuitive, thermal resources will play a crucial role in providing the stability needed to safely integrate more community solar and wind resources to the Yukon grid. Intermittent renewable resources need dependable capacity such as hydro and diesel in the background to support sudden fluctuations in their electricity production, as well as to prevent power outages when the wind is not blowing, or the sun is not shining. As part of the Yukon's resilient energy future, balancing resources like diesel generators and battery storage systems will help to stabilize the frequency of the power supply and provide power when other resources are not available.

The power centres will be built in three completion phases through to winter 2035 – each of which will have its own design, procurement, construction, and operation activities. This approach ensures that dependable sources of winter power are available to Yukoners when needed while at the same time providing flexibility for Yukon Energy to respond to changes in climate policy targets, market conditions, electrical demand, and the advancement of emerging technologies, local renewable projects and potential interties with other jurisdictions.

For these same reasons, Yukon Energy will be assessing each of the three thermal power centre sites for a higher level of thermal generation capacity than what is expected to be installed by 2040. This approach allows Yukon Energy to respond quickly to changing electricity load forecasts and keep electricity flowing should renewable or other projects be delayed.

The south power centre site will be assessed for up to 30 MW of thermal generation. The two north sites (i.e., the primary and contingency site) will be assessed for up to 60 MW thermal generation at each site. Installation of more than 30 MW of thermal capacity at any site will include redundancy design as required to ensure that a new capacity planning risk (N-1) is not created.

Table 1 Whitehorse Power Centres Project Proposed Completion Phases.

Completion Phase	Description	Expected In-Service Date
Phase 1: South Power Centre Build	- Construct south power centre with 15 MW of capacity.	Winter 2027
Phase 2: North Power Centre Build	- Construct one north power centre with 30 MW of thermal generation. - Construct substation and transmission infrastructure. - Add incremental capacity to the south power centre as needed (up to an additional 15 MW) to meet load growth in the Whitehorse area while the north power centre is being built. - Review load forecasts and availability of generation supply. If required, determine feasibility of adding generation capacity to existing north power centre.	Winter 2030
Phase 3: Expand Power Centres	- Add incremental capacity to the north power centre as needed and/or construct second north power centre if expansion of existing north power centre built in Phase 2 is not feasible or demand for power is expected to exceed capacity limits at the north site.	Winter 2035

All sites for the Whitehorse Power Centres are located within the Traditional Territories of Kwanlin Dün First Nation and Ta'an Kwäch'än Council, and the Municipality of Whitehorse or within rural areas directly adjacent to Whitehorse municipal boundaries. Yukon Energy has identified ten potential sites for the three generation centres and one site for the substation.

At this time, more work is required to select the three generation sites and one substation site that will be presented in Yukon Energy's Yukon Environmental and Socio-economic Board (YESAB) Project Proposal. Yukon Energy is considering multiple criteria for site selection, including but not limited to, technical feasibility, impacts on nearby residents and sensitive receptors, environmental impacts, and life cycle costs. Yukon Energy must also secure needed agreements/approvals for site ownership or lease. The sites are planned to be selected by Fall 2025 to enable completion of site assessment activities required for the Project Proposal submission by late 2025 or early 2026.

Yukon Energy conducted a technical assessment of potential fuel sources for the power centres. The study considered diesel, liquefied natural gas (LNG), and renewable diesel, among other fuel types. The study considered multiple criteria including availability and reliability of fuel delivery, storage requirements, cost, and greenhouse gas emissions. Diesel and LNG were identified as the two preferred fuel types given their established supply chains. More work is required to select the fuel type and to determine whether both fuels or a blend of fuels (i.e. bi- or dual fuel) is feasible. In the short-term the Whitehorse Power Centres south generation site to be initially developed by winter 2027/28 may be equipped with rental diesel units to ensure that immediate winter demands for power can be met. The selected fuel(s) will be shared with the Board once confirmed.

The capacity of each proposed generating station is greater than 5 MW and will trigger a YESAB Executive Committee screening. Yukon Energy assumes that a Part 3 *Public Utilities Act* Energy Project and Operation Certificate will also be required prior to start of construction of the new permanent thermal generation facilities. The anticipated Part 3 process includes an OIC being issued declaring this to be a regulated project, Yukon Energy providing an application to the Minister, and the YUB holding a public hearing prior to issuing a report to the Yukon government who then issues the required Certificates. The process may take approximately nine months to complete and can begin once the YESAA Project Proposal is submitted. Yukon Energy will seek an Energy Certificate prior to commencing construction.

The Project will provide thermal generation and associated assets with assumed operating lives of 40 years and potential to extend their working life for decades beyond that, if required. If Yukon Energy reaches a point where these thermal assets are no longer required, and has enough renewable capacity, Yukon Energy will stop using them.

Costing of the South Whitehorse Power Centre:

Cost of constructing and commissioning the south Whitehorse Power Centre's initial 15 MW (currently scheduled to be in-service by winter 2027/28) was not included in Yukon Energy's 2025-

2027 GRA revenue requirements due to uncertainty of costs and timing of completion.¹ Current updates indicate the following for this first phase of the Whitehorse Power Centres Project:

- Yukon Energy now forecasts that this initial 15 MW development for the south power centre will be in service by winter 2027/28.
- The cost of the south power centre that is expected to be in service by winter 2027/28 is approximately \$56.9 million [Class 4 cost estimate, -30% to +50% accuracy range]. If this cost is added to rate base in 2027, the estimated impact is approximately \$2.4 million increase in the revenue requirements [including depreciation and return on rate base on mid-year basis] or 1.85% added rate increase [before considering the removal of the diesel rentals as noted further below].
- With this power centre in service with 15 MW capacity²:
 - Yukon Energy would avoid renting an additional five diesel units to address the incremental capacity shortfall of 8 MW for 2027/28 winter identified in the response to YUB-YEC-1-30: and
 - Yukon Energy would be able to reduce the number of rental units from 22 to 18, considering the 15 MW total added capacity for the south centre would address the 8 MW capacity shortfall for 2027/28 as well as provide additional 6.4 MW dependable capacity [15 MW with 96% effective load carrying capacity factor = 14.4]. If the south centre cost is included in the revenue requirements, the cost related to reduced diesel rentals would be removed from the revenue requirements [approximately \$1 million] in addition to the avoided new diesel rentals.

The following table shows the dependable capacity shortfall with the south centre capacity included³.

¹ See Application, Appendix 5.4A, footnote 1 at page 5.4A-2, which noted that updates would be provided as available during the current GRA procedure.

² Yukon Energy is planning to install 15 MW permanent modular units. If the modular units are not available on time, Yukon Energy may use a combination of modular Yukon Energy-owned units and rental units until the permanent units can be installed.

³ The increase in dependable capacity for 2027/28 of 14.4 MW reflects the inclusion of the south centre capacity with [15 MW with 96% effective load carrying capacity factor = 14.4] and reduction in diesel rentals in row D.

Yukon Energy Corporation
 2025-27 General Rate Application
 YUB-YEC-1-8 (a-b) Attachment 1
WPCP Update

	in MW	2025/26	2026/27	2027/28
A	Non-industrial peak under N-1	121.9	129.8	136.1
B	Dependable capacity under N-1	88.6	94.2	108.8
C=B-A	Capacity shortfall under N-1	-33.3	-35.6	-27.4
D	Diesel rentals=22 for 2025/26 and 2026/27, 18 for 2027/28	33.7	33.7	27.5
E=C+D	Capacity (Shortfall)/Surplus with diesel rentals	0.4	-1.9	0.2

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 23

2
3 **ISSUE:** Growing demand for electricity

4
5 **QUOTE:** Distribution networks will need to be expanded and modernized to
6 efficiently distribute and re-distribute power.

7
8 **PREAMBLE:** The Board seeks clarification of the above statement.

9
10 **QUESTION:**

11
12 a) Please explain what is meant by “re-distribute” power.

13
14 **ANSWER:**

15
16 **(a)**

17
18 The referenced quote is from the Electricity Canada publication, *Electricity is Essential for*
19 *the Next Decade*, as indicated in footnote 5 on pdf page 23. This phrase was included in
20 the discussions under the topic “How to build a grid” and Yukon Energy’s understanding
21 is that this refers to the various activities that redistribute power on a grid, including:

- 22
- 23 • batteries/ power storage for future redistribution;
 - 24
 - 25 • customers providing power to the grid when their own renewable energy supply
 - 26 exceeds their load;
 - 27
 - 28 • utility visibility and control of the different supplies and demands of electricity so
 - 29 that utilities are able to balance electricity load and generation minute/minute and
 - 30 respond quickly to changing conditions; and
 - 31
 - 32 • two-way flow of electricity cases in general and the variability of these sources.
 - 33

34 Overall, this phrase also appears to recognize that investments are needed to expand
35 and modernize the grid in line with the climate change initiatives, including integration of
36 the intermittent energy resources such as wind and solar, and how the use of the
37 electricity is changing, including transition to the electricity in home heating and
38 transportation sectors.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 31 and 193

2
3 **ISSUE:** Government Grant Funding

4
5 **QUOTE:** PDF page 31:

6 Yukon Energy has sought \$50 million in federal grant funding through
7 NRCan's Smart Renewables and Electrification Pathways Program's
8 (SREPs') Utility Support Stream (USS) to offset the cost of a portion of
9 its capital investments between 2025-2027.

10 ...

11 Yukon Energy is also supporting Yukon Development Corporation's
12 funding request from the SREP Critical Regional Priorities Stream, as
13 well as funding specifically related to the Mayo Rock Slope
14 Remediation and Surge Chamber projects.

15
16 PDF page 193:

17 As Yukon Energy has no certainty regarding capital grant funding at
18 this time, potential impacts of receiving funding that would offset
19 Revenue Requirement have not been included in the GRA. Depending
20 on the amount and timing of capital funding, it could have a significant
21 impact on Yukon Energy's return. Yukon Energy will update the Board
22 of the status of these funding applications throughout this regulatory
23 process as information becomes available.

24
25 **PREAMBLE:** The Board seeks clarification of the above statements.

26
27 **QUESTION:**

- 28
29 a) What is YEC's success rate for submitting applications for approval for funding?
30 For successful applications, what is the general time lapse from submission of
31 application to approval of the application?
32
33 b) For the SREP application, please provide a breakdown of the proposed grant
34 dollars by GRA test year for the projects YEC has applied for or intends to apply
35 for.

- 1 c) What is YEC's best estimate of dates when it expects a decision to be made on
2 SREP funding for each of the projects applied for?
3
- 4 d) Does YEC's current GRA include in its forecast federal grant funding (to both
5 Yukon Development Corporation (YDC) and YEC)? Please explain.
6
- 7 e) If the current GRA does not include in its forecast federal grant funding, how does
8 YEC plan to account for such if federal grant funding is approved. If approval
9 occurs after the completion of the GRA process, how will this impact approved
10 rates?
11
- 12 f) YEC has stated that "If successful, contributions provided would partially offset
13 total costs for specified projects." If federal grant funding occurs after the close of
14 record for this proceeding, how does YEC plan to prevent double dipping
15 (collection of project costs through rates and receipt of federal grants for the same
16 projects)?
17
- 18 g) Regarding YDC and SREP, what dollar amount is YEC requesting?
19
- 20 h) If YDC is successful, will all federal grant dollars flow to YEC? Please explain.
21
- 22 i) What is the expecting timing from submission of the YDC application to the
23 issuance of a decision regarding the grant funding?
24
- 25 j) Please provide the amounts for the proposed YDC funding for SREP for each of
26 the YEC 2025-2027 test years.
27
- 28 k) At PDF page 193 of the application, YEC identifies funding it is pursuing from
29 federal and territorial sources to reduce costs to ratepayers. Please provide an
30 update to the programs identified as the SREP Utility Stream; SREP Critical
31 Regional Priorities Stream; NRCan, and any other programs not previously
32 identified but relevant to the 2025-2027 test years as of the date of the response
33 to this IR.
34
- 35 l) Please confirm that the capital projects described in the application are not
36 dependent on the confirmation of the receipt of funds from the above noted grant
37 programs or other sources of contributed funds. If this cannot be confirmed, please

1 identify any projects which depend on the receipt of grants or other forms of
2 contributed funding. For any projects so identified, please briefly explain how the
3 completion the project would be impacted by a determination that grants, or other
4 contributed funding, will not be provided at expected levels.

5

6 **ANSWER:**

7

8 **(a)**

9

10 Yukon Energy does not keep detailed statistics (success rates) on funding submissions,
11 although a general response is that the success of a grant application varies and is
12 dependent on multiple factors including the scope of the project, the amount of funds being
13 requested, availability of total funds in the grant program, number of other applicants,
14 government priorities at the time, etc.

15

16 Some examples of previous and current funding Yukon Energy have received includes:

17

- 18 • \$22.7 million for the Mayo to McQuesten Transmission Line Replacement Project;
- 19
- 20 • \$16.5 million for the Battery Energy Storage System (included as a contribution to
- 21 the project in this GRA); and
- 22
- 23 • Over \$0.8 million for Demand Side Management projects in 2023 and 2024.
- 24

25

26 While there is no general time lapse from submission to approval, Yukon Energy notes
27 that successful applications may take years to complete.

28

29 **(b)**

30

31 SREPs has three streams: indigenous-led projects, utility projects and regional priorities.
32 Yukon Energy applied to the utility stream under the deployment sub-stream. Based on
33 the deployment sub-stream program requirements, Yukon Energy applied for \$25.442
34 million of grant funding. Contributions from SREPs would be received on a government
35 fiscal-year basis. The breakdown by government fiscal year for grant contribution
applications is detailed below.

	(\$ millions)						
	April 2025- March 2026	April 2026- March 2027	April 2027- March 2028	April 2028- March 2029	April 2029- March 2030		Total
SREP Funding Request	\$ 1.820	\$ 4.547	\$ 6.085	\$ 4.140	\$ 8.850	\$	25.442

Yukon Energy intends to apply for additional funding through the utility stream pre-feasibility sub-stream, which is not currently open for applications. An Application Guide for the pre-feasibility stream has not been made available by Natural Resources Canada, so it is not possible to say which projects will be applied for. The maximum funding request for the SREP utility stream is \$50 million.

(c)

Yukon Energy's SREP application of \$25.442 million detailed in part (b) was submitted on April 2, 2025. As per the Application Guide, Natural Resources Canada's Service Standards are that a decision on funding will be made within 105 days of receipt of the application (July 16). As of July 17, 2025, Yukon Energy had not received a response.

On August 6, 2025, Yukon Energy was notified that the SREP utility stream deployment sub-stream funding request of \$25.442 million was not selected for approval.

(d)

This GRA does not assume any federal grant funding is received. In conversations with staff from federal grant funding agencies and peers in the utility sector, we understand that competition for grant funding has increased while the amount of funding available has remained the same or been redirected to other federal priorities. Therefore, it would be presumptuous to assume a Yukon Energy application for grant funding would be approved until formal notice is received.

(e) and (f)

If Yukon Energy learns that federal grant funding is approved, Yukon Energy will inform the Yukon Utilities Board on a timely basis. If approval occurs after the completion of the GRA process and the funding could have a material impact on rates, Yukon Energy will still inform the Yukon Utilities Board and could propose a change to existing rates, such as through a refund rider.

(g) and (h)

Yukon Development Corporation (YDC) has prepared applications to submit to SREP for approximately \$176 million. Yukon Energy would request YDC contribute to Yukon Energy 100% of the dollars as they are all related to Yukon Energy projects. However, YDC would have to approve this funding through to Yukon Energy.

(i)

As per the Application Guide, Natural Resources Canada's Service Standards are that a decision on funding will be made within 105 days of receipt of the application. However, as per Yukon Energy's response to part (c), the deadline for its utility stream application was not adhered to.

(j)

Contributions from SREPS would be received on a government fiscal-year basis. The breakdown by government fiscal year for the proposed YDC funding for SREP are as follows.

Project	(\$ millions)				
	Total Funding Request	April 2025- March 2026	April 2026- March 2027	April 2027- March 2028	Beyond March 2028
Mayo A Hydro Plant Renewal	\$ 26.250	\$ -	\$ 0.250	\$ 1.000	\$ 25.000
Mayo Rock Slope Stabilization and Surge Chamber Replacement	\$ 49.600	\$ 20.700	\$ 26.700	\$ -	\$ 2.200
Wareham Dam Spillway	\$ 50.000	\$ 3.745	\$ 18.505	\$ 18.425	\$ 9.325
Whitehorse Power Centre	\$ 50.000	\$ 0.900	\$ 1.200	\$ 18.500	\$ 29.400
AMI Infrastructure Study	\$ 0.450	\$ 0.050	\$ 0.050	\$ 0.035	\$ 0.315
	\$ 176.300	\$ 25.395	\$ 46.705	\$ 37.960	\$ 66.240

(k)

On June 13, 2025, Yukon Energy applied through NRCan's Office of Energy Research and Development for funding to complete a study to define current infrastructure limitations and the common information model (CIM) to support the deployment of AMI in Yukon Energy's distribution communities. CIM is a standardized way to represent and exchange information about electrical networks and equipment. It facilitates data

integration between different systems within a utility, promoting interoperability and simplifying data exchange.

Contributions from the program would be delivered based on a government fiscal-year basis. The breakdown by government fiscal year is as follows:

		(\$ millions)						
		April 2025- March 2026	April 2026- March 2027	April 2027- March 2028	April 2028- March 2029	April 2029- March 2030	Total	
NRCan Funding Request	\$	0.100	\$ 0.350	\$ -	\$ -	\$ -	\$	0.450

Yukon Energy anticipates hearing whether this funding application was successful in the coming months. No specific timing for responses was provided by the funding agency.

(I)

Confirmed.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 35

2
3 **ISSUE:** Increasing the Supply of Dependable Winter Capacity

4
5 **PREAMBLE:** Impact of the BESS Project.

6
7 **QUESTION:**

8
9 a) What is the impact of the Bess Project contribution of \$16.5 million? When does
10 that factor into the rate base?

11
12 **ANSWER:**

13
14 **(a)**

15
16 The BESS project is forecast to be closed to rate base in 2026. The rate impact of the
17 \$16.5 million contributions is approximately -1.3% rate reduction in this Application [i.e.,
18 without the contributions, the required rate increase would have been approximately 1.3%
19 higher].

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 35 and 36

2
3 **ISSUE:** First Nation Partnerships/resource requirements

4
5 **QUOTE:** Like other businesses in the Yukon, Yukon Energy is not immune to
6 external pressures such as inflation, increased labour costs, and supply
7 chain delays and constraints experienced in recent years. Additional
8 resources are also required to direct, plan, execute and oversee the
9 way Yukon Energy responds to today's challenges. (PDF page 35)

10
11 As a public utility, we strive to fulfill commitments as outlined in Chapter
12 22 of the Umbrella Final Agreement including economic development,
13 employment, procurement and investment, amongst others. (PDF page
14 36)

15
16 **QUESTION:**

- 17
18 a) Please explain what commitments YEC is referring to in relation to its application,
19 and what is the potential impact on its revenue requirement, if any?
20
21 b) Are there any other obligations arising from other chapters of the Final Agreements
22 that YEC is appropriately fulfilling?
23
24 c) How does YEC plan to fill its resource requirements (staff or via contractors)?
25 Please explain.
26

27 **ANSWER:**

28
29 **(a) and (b)**

30
31 The second quote referenced above "As a public utility..." can be found on PDF page 32
32 as opposed to PDF page 36 as stated in the question.
33

34 Yukon Energy has either executed or is in the process of negotiating project agreements
35 with Yukon First Nation(s) on many projects including:

- Battery Energy Storage System;
- WRGS 20-Year Relicensing;
- Aishihik Long-Term Relicensing;
- Mayo 5-Year Relicensing;
- Mayo Spillway, Rock Slope and Surge Chamber; and
- Thermal Replacement.

Chapter 22 of the Umbrella Final Agreement and Yukon First Nation Final Agreement outlines provisions for Yukon First Nations to be provided with opportunities to maximize specific economic measures (e.g., training, employment, business and contracting opportunities, energy planning) and a First Nation's interest in strategic investments in the areas of renewable resources services and energy resources. The potential impact on revenue requirement, if any, could vary depending on the project. Chapter 22 also outlines that project agreements with First Nations may include other measures to mitigate negative socio-economic effects of a project on the First Nation.

Yukon Energy's participation in fulfilling obligations arising from other chapters of the Final Agreements is extensive. Many of the processes for regulatory review that exist today arise from the Final Agreement Chapters.

- **Chapter 5 Tenure and Management of Settlement Land:** Yukon Energy participates in the interpretation and legal defense of its encumbering rights related to our Whitehorse, Aishihik and Mayo hydro facilities.
- **Chapter 11 Land Use Planning:** Yukon Energy participates in land use planning with First Nations and Yukon Government when our assets such as hydro facilities are within a proposed planning area.
- **Chapter 12 Development Assessment:** The Yukon Environmental and Socio-economic Assessment Board process arises from Chapter 12. As a proponent for a project, Yukon Energy participates in the designated office or executive level screening processes.
- **Chapter 13 Heritage:** Yukon Energy participates in heritage planning and project effect mitigations for heritage resources.

- 1 • **Chapter 14 Water Management:** Yukon Energy participates in the Yukon Water
2 Board screening and licensing processes.

3
4 **(c)**

5
6 Yukon Energy plans to fill its resource requirements with staff. Implementing the above-
7 noted agreements and building relationships and trust with Yukon First Nation requires
8 time, and ongoing and consistent collaboration. Given the sensitivity of these
9 relationships, trust can be easily compromised. Staff members, as opposed to contractors,
10 are better positioned to consistently uphold the shared interests of the corporation, the
11 First Nation, and their collaborative relationship. Additional information on the status of
12 hiring is provided in YUB-YEC-1-38(d).

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 32

2
3 **ISSUE:** Other Regulatory Issues

4
5 **QUOTE:** Aside from the need to address revenue requirement shortfalls at
6 existing rates, the current Application does not identify other regulatory
7 issues that need to be addressed concurrently with the Application.

8
9 **PREAMBLE:** The Board requests further information.

10
11 **QUESTION:**

12
13 a) What other regulatory issues does YEC need to concurrently address with this
14 Application?

15
16 b) How does YEC propose to account for the costs of the regulatory issues it
17 proposes to address concurrently with this Application?

18
19 **ANSWER:**

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

22
23 The referenced quote is in section 1.3 of Tab 1 (PDF page 36), where Yukon Energy notes
24 that “the current Application **does not** identify other regulatory issues that need to be
25 addressed concurrently with the Application”, i.e., there are no other regulatory issues
26 [such as the need for a new deferral account, etc.] proposed in this Application.

1 **REFERENCE: AEY-YEC Terms and Conditions of Service Application**

2
3 **ISSUE:** Effect of AEY-YEC Terms and Conditions of Service Application

4
5 **PREAMBLE:** AEY-YEC 2025 Terms and Conditions of Service Application was
6 submitted December 30, 2024, and is currently before the Yukon
7 Utilities Board.
8

9 **QUESTION:**

- 10
11 a) Please explain how, if at all, YEC has taken into account the referenced 2025
12 Terms and Conditions of Service Application within the current GRA and its 2025-
13 2027 forecast revenue requirement.
14

15 **ANSWER:**

16
17 **(a)**

18
19 The impact of the proposed amendments/modifications to the Terms and Conditions of
20 Service is not included in the current Application. As indicated in response to AEY-YEC-
21 UCG-002 in the Terms and Conditions of Service proceeding, “the Utilities intend to utilize
22 the figures approved for both MILs and Schedule D in their next respective rate
23 applications filed after the approval date.” Any impacts from the changes to be approved
24 in the Terms and Conditions of Service proceeding will be reflected in the next GRA.

1 **REFERENCE: YEC 2025-2027 Application, PDF pages 36-37**

2
3 **ISSUE:** Yukon Energy Rates and Bills

4
5 **QUESTION:**

6
7 a) At PDF pages 36 and 37, YEC states that the Yukon Government provides for a
8 Winter Electrical Affordability Rebate (formerly, the Interim Electric Rebate) to
9 residential non-government customers. Please provide further details with respect
10 to this program including a description of the requirements to qualify as a
11 “residential non-government” customer.

12
13 **ANSWER:**

14
15 **(a)**

16
17 On April 1, 2025, the Government of Yukon replaced the Interim Electrical Rebate with the
18 Winter Electrical Affordability Rebate. This new rebate is 3.377 cents/kWh to a maximum
19 of 1,000 kWh per month for the electricity consumed by non-government residential
20 customers during the months of October through March. For electricity consumed by non-
21 government residential customers during the months of April through September, the
22 rebate is 0.000 cents/kWh. Prior to this change, the Interim Electrical Rebate provided a
23 2.262 cents/kWh rebate for up to the first 1,000 kWh per month for the whole year.

24
25 The news release from the Government of Yukon states that “starting in October 2025,
26 residential electricity consumers will see the new Winter Electrical Affordability Rebate
27 automatically applied to their bills, replacing the Interim Electrical Rebate” and “Budget
28 2025–26 allocates \$3.85 million” for this program.

29
30 The rebate is applicable to a maximum of 1,000 kWh per month for the electricity
31 consumed by non-government residential customers [Rate Schedules 1160, 1260, 1360
32 and 1460] during the months of October through March.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 39

2
3 **ISSUE:** Sales and Generation Forecast

4
5 **QUOTE:** The preliminary actual firm sales to non-industrial customers in 2024
6 was 433.5 GWh, about 8.2 GWh higher than the approved load forecast
7 and an increase of 28.8 GWh over 2023 actuals primarily due to higher
8 wholesales.
9

10 **PREAMBLE:** Final 2024 results of actual firm sales to non-industrial customers.

11
12 **QUESTION:**

- 13
14 a) Please update tables 2.1, and 2.2 with final and actual numbers. Please provide in
15 both PDF and Excel formats (Excel with formulae intact).
16

17 **ANSWER:**

18
19 **(a)**

20
21 Please see YUB-YEC-1-16 Attachment 1.
22

23 Please note that the only change from the Application is a small adjustment to the
24 secondary sales related load due to a change in allowance for losses. This also impacts
25 the net firm load and LTA generation numbers in Table 2.2 lines 5, 6, 24, 27 and 28

Table 2.1
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2023 Approved	2024 Approved	2023 Actual	2024 Actual	GRA Forecast		
						2025 Forecast	2026 Forecast	2027 Forecast
1	Residential							
2	Customers	1,858	1,898	1,889	1,968	2,008	2,048	2,088
3	Sales in MWh	17,693	18,090	17,328	18,989	19,369	19,756	20,151
4	MWh sales per customer	9.5	9.5	9.2	9.6	9.6	9.6	9.6
5	Revenue (\$000s)	2,532	2,611	2,472	2,749	2,823	2,879	2,937
6	Cents per KWh	14.3	14.4	14.3	14.5	14.6	14.6	14.6
7	General Service							
8	Customers	529	536	561	612	618	624	630
9	Sales in MWh	38,569	44,698	39,502	39,520	39,781	40,044	40,310
10	MWh sales per customer	72.9	83.4	70.5	64.6	64.3	64.1	64.0
11	Revenue (\$000s)	6,272	7,175	6,476	6,860	6,496	6,539	6,583
12	Cents per KWh	16.3	16.1	16.4	17.4	16.3	16.3	16.3
13	Industrial							
14	Sales in MWh	75,045	69,368	74,498	46,127	42,796	42,796	42,796
15	Revenue (\$000s)	9,772	8,809	9,586	6,888	5,724	5,628	5,628
16	Cents per KWh	13.0	12.7	12.9	14.9	13.4	13.2	13.2
17	Street lights							
18	Sales in MWh	168	168	168	172	171	171	171
19	Revenue (\$000s)	82	82	83	83	83	83	83
20	Cents per KWh	48.9	48.9	49.4	48.3	48.6	48.6	48.6
21	Space lights							
22	Sales in MWh	9	9	9	10	10	10	10
23	Revenue (\$000s)	2	2	3	3	3	3	3
24	Cents per KWh	27.3	27.3	29.2	26.5	26.9	26.9	26.9
25	Total Company - Firm Retail & Ind.							
26	Customers	2,387	2,434	2,450	2,580	2,626	2,672	2,718
27	Sales in MWh	131,484	132,333	131,504	104,818	102,127	102,777	103,439
28	Revenue (\$000s)	18,660	18,679	18,619	16,582	15,128	15,132	15,234
29	Cents per KWh	14.2	14.1	14.2	15.8	14.8	14.7	14.7
30	Wholesale sales							
31	Sales in MWh	351,291	362,365	347,704	374,831	373,662	381,929	390,420
32	Revenue (\$000s)	29,150	30,069	28,852	31,103	31,006	31,692	32,397
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	Total Company - Firm							
35	Sales in MWh	482,775	494,699	479,208	479,649	475,788	484,706	493,858
36	Revenue (\$000s)	47,810	48,748	47,471	47,685	46,135	46,824	47,631
37	Cents per KWh	9.9	9.9	9.9	9.9	9.7	9.7	9.6
38	Secondary							
39	Sales in MWh	2,931	2,931	2,214	3,699	2,931	2,931	2,931
40	Revenue (\$000s)	358	358	227	379	287	287	287
41	Cents per KWh	12.2	12.2	10.2	10.2	9.8	9.8	9.8
42	Total Company							
43	Sales in MWh	485,706	497,630	481,422	483,348	478,719	487,637	496,789
44	Revenue (\$000s)	48,168	49,106	47,698	48,064	46,422	47,112	47,918
45	Cents per KWh	9.9	9.9	9.9	9.9	9.7	9.7	9.6
46	Rider J (\$000s) at the 2023/24 GRA	33,999	41,844	25,432	35,154	40,954	41,681	42,474
47	Total Sales Revenues¹	82,166	90,950	73,130	83,218	87,376	88,792	90,392
48	Total Sales Revenues excluding secondary sales	81,809	90,592	72,903	82,839	87,089	88,505	90,105

Note:

1. Excludes revenues from other revenues.

Table 2.2
Summary of Energy Balance, Losses, Peak and Load Factor

Line No.	Description	2023 Approved	2024 Approved	2023 Actual	2024 Actual	GRA Forecast		
						2025 Forecast	2026 Forecast	2027 Forecast
	Sales and Losses							
1	Total Energy Sales	485,706	497,630	481,422	483,348	478,719	487,637	496,789
2	Losses - MWh	42,938	43,791	41,659	41,926	42,127	42,912	43,717
3	Losses - %	8.8%	8.8%	8.7%	8.7%	8.8%	8.8%	8.8%
4	Total Generation	528,644	541,421	523,081	525,274	520,847	530,550	540,507
5	Secondary Sales Related	3,190	3,189	2,473	3,979	3,189	3,189	3,189
6	Firm Load Generation	525,454	538,232	520,608	521,295	517,658	527,360	537,318
	Actual Generation - MWh							
	Hydro Generation							
7	Whitehorse	280,502	261,359	250,264	247,159	262,395	272,530	269,727
8	Aishihik	134,299	132,847	153,022	110,772	76,848	69,509	70,754
9	Mayo	71,595	73,895	71,144	65,606	73,731	116,867	125,089
10	Total Hydro	486,395	468,101	474,430	423,537	412,974	458,905	465,570
11	Wind Turbine	0	0	0	0	0	0	0
12	IPPs	1,964	14,289	1,962	8,847	17,717	17,717	17,717
	Diesel Generation¹							
13	Whitehorse	5,405	7,923	5,855	22,012	17,971	3,208	8,103
14	Faro	1,780	2,029	1,097	7,446	3,409	566	1,550
15	Dawson	987	1,669	3,108	6,679	184	24	76
16	Mayo	95	183	241	4,898	2,297	381	1,043
17	Total Diesel	8,267	11,804	10,300	41,036	23,861	4,179	10,772
18	LNG Generation¹	32,017	47,228	36,389	51,854	66,295	49,749	46,448
19	Total Thermal¹	40,285	59,031	46,689	92,890	90,156	53,927	57,220
	Source - %							
20	Hydro Generation	92.0%	86.5%	90.7%	80.6%	79.3%	86.5%	86.1%
21	LNG Generation	6.1%	8.7%	7.0%	9.9%	12.7%	9.4%	8.6%
22	Diesel Generation	1.6%	2.2%	2.0%	7.8%	4.6%	0.8%	2.0%
23	IPP Generation	0.0%	0.0%	0.0%	1.7%	3.4%	3.3%	3.3%
	LTA Generation - MWh							
24	LTA Hydro Generation	445,912	448,609	446,690	446,300	436,084	438,717	441,196
25	LTA Wind Generation	0	0	0	0	0	0	0
26	IPP Generation	1,964	14,289	1,962	8,847	17,717	17,717	17,717
27	LTA Thermal Generation	77,578	75,334	73,918	66,148	63,857	70,926	78,405
28	Total LTA Generation	525,454	538,232	522,570	521,295	517,658	527,360	537,318
	Peak - MW²							
29	Integrated System	119.5	123.2	102.7	111.6	127.4	132.2	136.2

Notes:

- 1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance and capital requirements reflecting short-term hydro generation forecasts.
- 2 Peak load is forecast to occur in December (forecasts assume weather normalized temperature) and includes industrial peak.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 40, Footnotes 2 and 3

2
3 **ISSUE:** Industrial sales

4
5 **QUOTE:** Footnote 2: 2023 actual sales included sales to Minto Mine as an
6 industrial customer for January-May 2023. After May 2023, the sales to
7 Minto reflect the load for care and maintenance under the general
8 service class.

9
10 Footnote 3: The grid power deliveries to VG [Victoria Gold] were
11 resumed in September 2024, however, lower than the previous
12 consumption levels as remediation work continued at the mine site. In
13 August 2024, based on the Yukon Government's request, a
14 receivership was appointed by the court to oversee the remediation of
15 the heap leach failure and its environmental impacts.

16
17 **QUESTION:**

18
19 a) For both 2023 and 2024, for Minto, please provide relative to approved forecast
20 what was the decrease in industrial sales and what was the increase in general
21 service sales.

22
23 b) For VG, starting in August 2024, were the sales to the court appointed receiver
24 treated as industrial sales? Please explain. Does VG still qualify as an industrial
25 customer? Please explain.

26
27 c) For VG, in 2024 what was the actual load compared to the approved forecast load?

28
29 d) Minto was recently sold to Selkirk FN. Will this impact the forecast sales to Minto?
30 Please explain.

31
32 **ANSWER:**

33
34 **(a)**

35
36 The 2023/24 GRA already reflected changes related to Minto, i.e., the sales for January-
37 May 2023 were included under the industrial customer class, while the sales after May

2023, reflecting the load for care and maintenance, were included under the general service class. The following table shows the variances between the actual and approved sales for Minto.

	2023	2024
Minto Mine - Industrial		
Sales in MWh - 2023/24 GRA	16,389	0
Sales in MWh - Actuals	16,342	0
Variance	-47	0
Minto Mine Care and Maintenance - General Service		
Sales in MWh - 2023/24 GRA	8,022	13,103
Sales in MWh - Actuals	9,317	5,462
	1,295	-7,641

(b)

Yes, the sales to VG under receivership are currently treated as industrial sales.

Due to the heap leach failure on June 24, 2024, power consumption was dramatically reduced, and the power line was de-energized on June 14, 2024, due to damage caused by wildfires. Therefore, there were no sales to VG between June 15, 2024, and September 13, 2024. When grid power deliveries to VG resumed in September 2024, consumption levels were lower than the previous consumption levels as remediation work continued at the mine site. There are still uncertainties regarding future loads and how long remediation will continue. However, Yukon government noted that it was not the government's intention to shut down VG when it put the mining company into receivership, and the goal won't be to close the Eagle gold mine or sell off Victoria Gold's assets, but rather to get the mine back to the state it was in before the failure.¹

After submission of this application, the Receiver PricewaterhouseCoopers has begun the process to sell the property² The new report also notes that "in their initial letters of intent, potential buyers are required to disclose their experience with mining and heap leach facilities. They are also asked to fill out a questionnaire for the First Nation of Na-Cho Nyäk Dun and share a proposed approach to obtaining the First Nation's support. The letter must also share any plans to reopen the mine."

¹ As reported by CBC on August 16, 2024 <https://www.cbc.ca/news/canada/north/victoria-goldupdate-august-16-1.7296458#:~:text=The%20Yukon's%20justice%20minister%20says,the%20company%20out%20of%20business.>

² As reported by CBC on June 27, 2025 "[Yukon's Eagle gold mine officially up for sale | CBC News](#)"

1 The current peak demand is approximately 2.5 MW, higher than the 1 MW threshold for
2 industrial customers as per Rate Schedule 39. As indicated above, there are still
3 uncertainties regarding whether the mine will reopen; however, both referenced news
4 releases state the intention of reopening the mine. VG has continued to be treated as an
5 industrial customer for billing purposes, which assumes ongoing mining operation.
6 Switching VG from the industrial customer class to the general service customer class
7 would also have implications for the RS 39 Fixed Charges, its calculation and how it is
8 recovered from customers. Yukon Energy will reassess this classification as time passes
9 and new information becomes available.

10
11 Please also see the response to YUB-YEC-1-22.

12
13 **(c)**

14
15 The actual sales for 2024 were at 23.3 GWh or 24.3 GWh lower compared to the approved
16 forecast load of 47.6 GWh.

17
18 **(d)**

19
20 In September 2024, the Yukon government's statement noted that it will "continue to
21 engage with the court-appointed Receiver on the sales process for the mine" and
22 "regardless of the outcome of this process, work on reclaiming the site will move ahead."³

23
24 Therefore, Yukon Energy understands that the sales to Minto under care and maintenance
25 will continue during the test years. However, the actual sales to date were lower than the
26 forecast, with actual sales for Jan-June 2025 at about 2 GWh compared to the forecast
27 sales of about 5.5 GWh/year for each test year.

28
29 Any potential sales to Minto as an industrial customer, or any changes due to the sale of
30 the mine to Selkirk First Nation, are unknown at this time.

³ See <https://yukon.ca/en/news/statementminister-energy-mines-and-resources-streicker-milestone-abandoned-minto-minesite#:~:text=%E2%80%9CWe%20continue%20to%20engage%20with,reclaiming%20and%20closing%20the%20site.%E2%80%9D>.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 40

2
3 **ISSUE:** Total firm generation load

4
5 **QUOTE:** The forecast total firm generation load for the 2025 test year is 517.7
6 GWh, about 0.7% lower than 2024 preliminary actuals, for the 2026 test
7 year is 527.4 GWh, about a 1.9% increase over 2025 forecast, and for
8 the 2027 test year is 537.3 GWh, about a 1.9% increase over 2026
9 forecast.

10
11 **QUESTION:**

- 12
13 a) Please explain, at a high level, why the forecast firm generation load growth is
14 expected to be the same (1.9 per cent) for both 2026 and 2027.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The firm generation load growth forecasts in 2026 and 2027 follow the growth in sales
21 which also assume about 1.9% growth in 2026 over 2025, and further 1.9% growth in 2027
22 over 2026. As the line losses are proposed to be at 8.8% for each test year, the firm
23 generation growth percentages are also at 1.9% in 2026 over 2025, and further 1.9%
24 growth in 2027 over 2026.

1 **REFERENCE: YEC 2025-2027 Application, PDF page 40**

2
3 **ISSUE: Non-firm secondary sales**

4
5 **QUOTE:** The actual secondary sales in 2023 were 2.2 GWh and preliminary
6 actual secondary sales for 2024 were 3.7 GWh. For the 2025-2027 test
7 years, the secondary sales forecast is 2.9 GWh for each test year, at
8 the same level as in the 2023/24 GRA and the average of 2023 and
9 2024 actual secondary sales.

10
11 **QUESTION:**

- 12
13 a) Please provide further information regarding the reasons for using the same
14 forecast level for non-firm secondary sales for each test year as was used in the
15 2023-2024 GRA by YEC.

16
17 **ANSWER:**

18
19 **(a)**

20
21 Due to uncertainties regarding the availability of secondary sales, Yukon Energy has
22 forecast secondary sales at the 2023/24 GRA approved level. This is the same level as
23 the average of actual secondary sales in 2023 (at 2.2 GWh) and in 2024 (at 3.7 GWh).

24
25 The actual secondary sales for the first six months were at 0.033 GWh compared to the
26 forecast of 0.7 GWh. Please see the response to YUB-YEC-1-24 (a).

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 41

2
3 **ISSUE:** IPP renewal generation

4
5 **QUOTE:** IPP renewable generation at LTA is forecast at 3.4% of forecast grid
6 generation in 2025, 3.4% in 2026 and 3.3% in 2027.

7
8 **PREAMBLE:** The Board seeks clarification on the above IPP renewable generation
9 at LTA forecast for the test years.

10
11 **QUESTION:**

12
13 a) When did IPP renewal [sic] generation first become available to YEC?

14
15 b) Does the answer to part (a) qualify as LTA? If so, relate this LTA definition to the
16 rationale for YEC's proposal for the fuel mix (LNG: Diesel) in Tab 3.2 of the
17 Application.

18
19 c) Please explain why LTA IPP renewal generation does not grow from 2025 to 2026
20 and why it decreases from 2026 to 2027.

21
22 **ANSWER:**

23
24 **(a)**

25
26 The first IPP deliveries were in November 2021.

27
28 **(b)**

29
30 The IPP delivery forecasts in this GRA reflect contracted LTA volumes as noted in part (c)
31 below. The response to part (a) does not address the test year LTA IPP generation
32 forecasts.

33
34 The forecast long-term average thermal requirements for the test years are determined
35 based on the long-term average forecasts for hydro generation for the firm load net of
36 IPPs. Based on direction provided by the Board, Yukon Energy reviewed the historical

1 LTA fuel mix and, based on updated information, proposed a change from 90% LNG and
2 10% diesel assumed in the previous GRAs, to 80% LNG and 20% diesel generation.

3
4 **(c)**

5
6 As shown in Table 2.2 of Tab 2, the IPP deliveries for 2025, 2026 and 2027 are forecast
7 at 17.717 GWh/year, which reflects the contract volumes based on Energy Purchase
8 Agreements signed with IPPs. These IPP generation forecasts assume the currently
9 connected seven IPPs, five solar and two wind. No other IPPs are expected to be
10 connected to the grid during the test years, therefore, the volume remains the same. The
11 reduction in percentage share of IPPs out of total load from 3.4% in 2026 to 3.3% in 2027
12 just reflects the increase in overall load, while the IPP volumes remain unchanged.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 42

2
3 **ISSUE:** Wholesale Sales to AEY

4
5 **QUOTE:** Accordingly, for the 2025, 2026 and 2027 test years, Yukon Energy
6 used the forecast provided by AEY. Firm wholesales for 2025 are
7 forecast in Table 2.1 at 373.7 GWh, which is 1.2 GWh (or 0.3%) lower
8 than 2024 preliminary actual, and 25.9 GWh (or 7.5%) higher than 2023
9 actuals as 2024 was impacted by colder than normal weather
10 conditions. Firm wholesales for 2026 are forecast at 381.9 GWh which
11 is 8.3 GWh (or 2.2%) higher than the 2025 forecast; firm wholesales for
12 2027 are forecast at 390.4 GWh which is 8.5 GWh (or 2.2%) higher
13 than the 2026 forecast.
14

15 **PREAMBLE:** The Board seeks clarification on the AEY forecast.

16
17 **QUESTION:**

18
19 a) Does YEC know if the wholesale sales forecast received from AEY is a forecast
20 for AEY budgeting purposes or is it determined for the Application test years?

21
22 b) How has YEC ascertained the correctness of the forecast provided by AEY?
23

24 **ANSWER:**

25
26 **(a)**

27
28 Yukon Energy requested the load forecast from AEY for GRA purposes; however, Yukon
29 Energy does not have details on whether the load forecast provided by AEY was prepared
30 for AEY budgeting purposes or GRA purposes.
31

32 **(b)**

33
34 The forecasts provided by AEY were reviewed by Yukon Energy and found to be
35 reasonable considering the preliminary actual sales for 2024 at the time of review, the
36 population growth projections for the City of Whitehorse, and AEY's evidence in the AEY's
37 2023/24 GRA regarding the expected connection of seven large general service
38 customers by late 2024.

1 **REFERENCE: YEC 2025-2027 Application, PDF page 43**

2
3 **ISSUE:** Major Industrial Sales

4
5 **QUOTE:** For the purpose of this GRA, 21.0 GWh/year sales forecast for each
6 2025, 2026 and 2027 test years. (footnote removed)

7
8 **QUESTION:**

9
10 a) Please provide the actual sales for VG for the first six months of 2025.

11
12 b) Are there any aberrations in 2025 that would affect the monthly average of those
13 six months? Please explain.

14
15 c) At this time, does YEC have any newer information that may affect the VG sales
16 forecast for 2026 and 2027? Please explain.

17
18 **ANSWER:**

19
20 **(a) and (b)**

21
22 The actual sales to VG for the first six months of 2025 were about 6.0 GWh compared to
23 the forecast sales of 10.4 GWh for the same period. The average monthly sales for those
24 six months were at around 1 GWh [higher in the first three months, averaging about 1.2
25 GWh/month and lower for the next three months, averaging about 0.8 GWh/month]
26 compared to the average 1.75 GWh/month forecast in the Application.

27
28 Further to the above, VG was disconnected due to a breaker failure in July 2025, then
29 briefly reconnected, and disconnected again due to forest fire damage to the transmission
30 line that feeds the mine. Therefore, there were only about 8,000 kWh sales in July 2025.

31
32 **(c)**

33
34 There are still uncertainties around VG load forecasts. Yukon Energy does not have any
35 new, reliable information at this time that would affect forecasts for 2026 and 2027. Please
36 also see the response to YUB-YEC-1-17 (b).

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 44-45

2
3 **ISSUE:** Yukon Energy Firm Retail Sales

4
5 **QUOTE:** Retail sales are forecast at 59.3 GWh for the 2025 test year, 59.9 GWh
6 for the 2026 test year and 60.6 GWh for the 2027 test year compared
7 to actual sales of 57.0 GWh in 2023 and preliminary actual sales of 58.7
8 GWh in 2024.

9
10 **PREAMBLE:** The Board seeks further information.

11
12 **QUESTION:**

13
14 a) Please explain and provide further details by rate class on how YEC developed its
15 firm retail sales forecast.

16
17 b) Did YEC look at anything else other than the Yukon Bureau of Statistics to inform
18 its firm residential sales forecast? Please explain.

19
20 c) Did YEC undertake any direct consultations with its General Service customers to
21 inform its firm general service sales forecast? Please explain.

22
23 d) Please provide the actual sales for firm lighting sales for the first six months of
24 2025.

25
26 e) Are there any aberrations in 2025 that would affect the monthly average firm
27 lighting sales of those six months? Please explain.

28
29 f) Did YEC consult with any communities regarding increased lights for the three-
30 year forecast period? Please explain.

31
32 **ANSWER:**

33
34 **(a)**

35
36 Yukon Energy's firm retail sales consist of sales to residential customers, general service
37 customers, lighting customers and industrial customers.

1 **Residential Class**

2
3 The residential class sales are forecast to increase by 2% in 2025 over 2024 results, and
4 a further 2.0% increase in 2026 over 2025 forecast, and a 2.0% increase in 2027 over
5 2026 forecast.

6
7 As reviewed in response to b) below, the growth rate of 2%/year was applied over the
8 2024 results, which is consistent with the population growth projections by the Yukon
9 Bureau of Statistics, which shows a population growth projection for 2025-2027 at around
10 2%. The number of customers was also assumed to increase by 2%/year.

11
12 **General Service Class**

13
14 The general service class sales are forecast to increase by 0.7% in 2025 over 2024
15 actuals, and a further 0.7% increase in 2026 over 2025 forecast, and a 0.7% increase in
16 2027 over 2026 forecast.

17
18 Similar to the residential sales forecast, the growth rate was applied over the 2024 results;
19 however, considering the recent growth in commercial sales was lower than the growth
20 rate for the residential class, a half of the residential class growth rate was applied to the
21 general service class [i.e., 1%/year compared to 2%/year for the residential class]. For
22 example, AEY's commercial sales growth between 2016 and 2023 was at 1% compared
23 to 3.1% growth in residential sales, and for the last five years, AEY residential sales growth
24 was 2.3% compared to only 0.1% commercial sales growth.

25
26 The growth rate of 1% was applied to general service sales excluding Minto and Faro
27 remediation project related loads, then the separate forecast was prepared for those two
28 larger general service customers and then the forecasts were combined to get the total
29 general service sales forecast. Therefore, the total annual growth rate of 0.7% noted
30 above is lower than the 1%/year growth rate applied to general service class sales
31 excluding Minto and Faro.

32
33 **Lighting**

34
35 The lighting-related sales are not significant; therefore, the forecasts for 2025, 2026 and
36 2027 are based on the 2024 results. Please also see the response to parts (d) to (f) below.

1 **Industrial Class**

2
3 Victoria Gold and Hecla Yukon continue to be forecast as major industrial customers
4 during the test years. Considering the significance of the load of the industrial customers,
5 Yukon Energy followed up with each industrial customer.

6
7 As indicated in section 2.2.2 of Tab 2:

- 8
9 • Based on the information provided by Hecla Yukon, the near-term loads were
10 expected to remain within the 2024 approved level; accordingly, the forecast for
11 each 2025, 2026 and 2027 test years is 21.8 GWh.
12
13 • There are still uncertainties regarding future Victoria Gold loads and how long the
14 restoration will continue. The Receivership appointed for Victoria Gold was unable
15 to provide the load forecast that could be used for the test years, citing
16 uncertainties around the restoration work; however, it highlighted expected added
17 loads for new water plant equipment. The December 2024 actual sales were at
18 around 1.2 GWh/month, however, the mine load was curtailed in December 2024
19 to address generation capacity limitations due to Mayo hydro plant issues and
20 issues with the transmission equipment. Therefore, Yukon Energy, for the purpose
21 of 2025-2027 GRA, assumed 21.0 GWh/year forecast load for each test year
22 based on around 1.7 GWh/month sales. As noted in response to YUB-YEC-1-22,
23 there are still uncertainties around VG load, and for the first six months of 2025 the
24 actual sales were lower than the forecast. Please also see the response YUB-
25 YEC-1-17 (b).

26
27 **(b)**

28
29 In addition to the Yukon Bureau of Statistics population growth projection, Yukon Energy
30 also reviewed the historical growth in residential sales.

31
32 The following table shows the actual sales between 2019 [the year just before Covid-19]
33 and 2024 and forecast sales for 2025 through 2027. As the table illustrates, the actual
34 sales increased significantly in 2020 due to pandemic related restrictions; however, the
35 average increase in post-COVID-19 sales was close to 0% highlighting the reduction in
36 usage-per-customer, until 2024, when the sales increased by 9.6%, again, mostly due to

a change in usage-per-customer. The usage-per-customer for 2025-2027 are forecast to remain at the 2024 level, which was among the highest as shown in the table.

The growth rate for 2025 was applied to the 2024 results, which already reflect the higher increase compared to previous years. Yukon Energy believes that the forecast increase of 2%/year is a reasonable assumption.

	Total Residential Sales, MWh	Annual Change, %	Average Number of Customers	Annual Change, %	Usage per Customer, MWh	Annual Change, %
2019	15,384		1,730		8.9	
2020	17,331	12.7%	1,778	2.8%	9.7	9.6%
2021	17,421	0.5%	1,813	2.0%	9.6	-1.4%
2022	17,334	-0.5%	1,822	0.5%	9.5	-1.0%
2023	17,328	0.0%	1,889	3.7%	9.2	-3.6%
2024	18,989	9.6%	1,968	4.2%	9.6	5.2%
2025F	19,369	2.0%	2,008	2.0%	9.6	0.0%
2026F	19,756	2.0%	2,048	2.0%	9.6	0.0%
2027F	20,151	2.0%	2,088	2.0%	9.6	0.0%

(c)

The two specific customers were consulted as the impact from those customers is notable, representing about 1/3 of the total general service class sales.

Yukon Energy consulted with Faro Mine Remediation Project as it is the single largest general service customer. The customer indicated that the power consumption for the 2025-27 years would be around 11 GWh/year. However, considering that the projection provided by the customer was higher than the actual results for the previous years [2022 at 9.7 GWh, 2023 at 9 GWh and 2024 at 8.0 GWh¹], Yukon Energy used 2024 actual sales at 8 GWh as the forecast for each 2025, 2026 and 2027 test years. For the first six months of 2025, the sales to the Faro Mine Remediation Project were about 4.5 GWh.

There are uncertainties regarding Minto, the second largest general service customer. As indicated in response to YUB-YEC-1-17 (d), the Yukon government's September 2024 statement noted that regardless of the outcome of the sale process of the mine assets,

¹ On page 2-7 of Tab 2 of the Application, Yukon Energy noted that the actual sales for 2024 were at 7.8 GWh. The correct number is 8 GWh.

1 work on reclaiming the site will move ahead. Therefore, Yukon Energy used the 2024
2 actual sales of 5.5 GWh as the forecast for each of the 2025, 2026 and 2027 test years.
3 However, actual sales to date were lower than the forecast, with actual sales for Jan-June
4 2025 at about 2 GWh compared to the forecast sales of about 5.5 GWh/year.

5
6 Yukon Energy did not consult with other general service customers, considering the fact
7 that, excluding the Faro Remediation Project and Minto, the balance of general service
8 sales are not significant compared to total sales.

9
10 **(d) to (f)**

11
12 The total sales for lighting customers for the first six months of 2025 were 0.073 GWh.

13
14 Generally, the sales for lighting customers do not change significantly. Some adjustments
15 could affect the reported sales volumes. For example, there was an adjustment of 680
16 kWh in January. However, the lighting sales are a small fraction of the total sales,
17 representing less than 0.05% of total sales and do not notably impact the revenues.
18 Therefore, Yukon Energy did not specifically consult with any communities regarding
19 increased lights for the three-year forecast period.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 46

2
3 **ISSUE:** Secondary sales

4
5 **QUOTE:** The actual secondary sales in 2023 were at 2.2 GWh compared to
6 forecast sales of 2.9 GWh, and the preliminary actual sales for 2024
7 are 3.7 GWh compared to forecast sales of 2.9 GWh. For the 2025-27
8 test years, the secondary sales forecast is at 2.9 GWh for each test
9 year which is the same as approved in the 2023/24 GRA and also equal
10 to the average of 2023 and 2024 actual sales.
11

12 **PREAMBLE:** The Board seeks further information.

13
14 **QUESTION:**

15
16 a) Did YEC review any generation modelling (for example, new renewables coming
17 online) to ascertain whether there are any opportunities for increased secondary
18 sales in the forecast? Please explain.

19
20 b) Will the availability of the BESS project in any way influence secondary sales
21 forecast? Please explain.
22

23 **ANSWER:**

24
25 **(a)**

26
27 Yukon Energy did not conduct generation modeling because no new renewable energy
28 sources are planned to come online during the test years. The actual secondary sales for
29 the first six months of 2025 were at 0.033 GWh compared to the forecast of 0.7 GWh due
30 to lower-than-average water availability at the hydro facilities, including later than
31 anticipated freshets in the Aishihik and Marsh Lake water basins, and increased spill due
32 to spinning reserve requirements for integration of intermittent renewables. The available
33 renewable energy is projected to remain at these lower than average levels during the test
34 years and therefore, secondary sales are expected to be at or below the forecast.
35

36 **(b)**

37 The BESS has limited influence on secondary sales as the planned operation is for
38 managing demand fluctuations of the grid and it will not be charged and discharged at its

1 full capacity on a daily basis. The BESS may reduce the amount of spinning reserve that
2 the hydro units need to carry during the spring and fall shoulder months, meaning more
3 surplus renewable energy may be available. However, there is a limited influence on the
4 secondary sales forecast because the available renewable energy from hydro is projected
5 to be below average due to low water availability during the test years.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 46

2
3 **ISSUE:** Line Losses

4
5 **QUOTE:** The line losses are calculated at the Yukon Energy grid load level as
6 the variance between metered generation and sales. The 2023/24 GRA
7 approved forecast losses were 8.8%. Actual losses were 8.7% in 2023
8 and preliminary actual losses in 2024 were also at 8.7%. The losses
9 are forecast at 8.8% for the 2025-2027 test years which is the same as
10 the approved losses in 2023/24 GRA and at the level of average for
11 2022-2024 actuals at 8.8% [2022 at 9.0%, 2023 and 2024 at 8.7%].
12

13 **PREAMBLE:** The Board seeks further information.
14

15 **QUESTION:**
16

- 17 a) Does YEC employ newer technologies and has YEC undertaken projects with the
18 goal of reducing line losses? Please explain.
19
20 b) Please provide the final line loss percentage for 2024.
21
22 c) If the 2024 final actual line loss percentage did not change from the 2024
23 preliminary actual, and the response to part (a) is affirmative, then would the
24 average of 2023 and 2024 provide a better predictor for line loss for the three test
25 years? Please explain.
26

27 **ANSWER:**
28

29 **(a)**
30

31 Yes, Yukon Energy has implemented newer technologies and is undertaking several
32 infrastructure projects that contribute to reducing line losses. However, it is important to
33 note that line loss reduction is typically a secondary benefit, with primary drivers being
34 system reliability, contingency response, and geographic constraints.¹ Key infrastructure
35 projects completed or in progress that would contribute to reducing line losses include:

¹ Yukon Energy is transmitting over long distances to meet light load demands in remote communities. The transmission lines are radial in nature with multiple failure points and often routed through difficult terrains. Strategic placement of generation resources will be key to deal with this challenge.

-
- 1 • **Battery Energy Storage Systems (BESS):** Deployed near the major load center,
2 Whitehorse. The BESS project helps reduce long-distance power transfers from
3 Mayo and Faro by 4 to 6 MW during peak events, thereby lowering associated
4 losses.
 - 5
 - 6 • **Reactive Power Management:** Yukon Energy uses line-connected reactors,
7 STATCOMs, and automatic switching schemes to manage voltage and reactive
8 losses. This is particularly critical on long, lightly loaded 138 kV lines.
 - 9
 - 10 • **Strategic Generation Placement:** Yukon Energy has invested in regional thermal
11 generation replacement capacity, including:
 - 12
 - 13 ○ 6.5 MW in Dawson,
 - 14 ○ 5 MW in Faro, and
 - 15 ○ 5 MW in Whitehorse.
 - 16

17 These projects reduce the need for power imports across long corridors, especially during
18 peak winter conditions, which in turn helps to minimize line losses.

19

20 Yukon Energy has conducted preliminary evaluations of options to reduce line losses by
21 twinning the highest-loss transmission lines, including:

- 22 • **Aishihik–Takhini (L171):** 130 km in length, carrying up to 35.5 MW of dependable
23 winter renewable generation²; and
- 24
- 25 • **Takhini–Carmacks (L170):** 158 km, facilitating northward transfers in summer
26 and southward imports during winter peaks, including power from rental generation
27 in Faro and Mayo.

28 While twinning or reconductoring of these lines could theoretically reduce losses – Aishihik
29 -Takhini alone accounted for 2.4% of total system losses in 2022 – the cost of such
30 upgrades is not economically justified based on energy savings alone. At an estimated \$1
31 million per kilometer (Class 5 estimate: -50%/+100%), each of these projects would
32 represent an investment of over \$130–160 million, excluding associated substation
33 upgrades, environmental permitting, and access infrastructure. As a result, Yukon Energy
34 is not pursuing twinning or reconductoring of these lines as a loss reduction strategy.

35 Instead, Yukon Energy's focus is on the following:

² The AGS can provide up to 37 MW; after consideration of Forced Outage Rate, the dependable capacity is 35.5 MW.

- Adding more winter generation near the Whitehorse load center, including the proposed Whitehorse Power Centers Project; and
- Upgrading the Whitehorse-area transmission system from a radial, frontier-style network into a modern, urban system with greater redundancy and reliability.

This approach will:

- Reduce long-distance imports during winter peaks;
- Minimize losses on L170 and the Mayo-Carmacks transmission lines not by duplicating line infrastructure, but by reducing the need to rely on it under normal and contingency conditions; and
- Improve system resilience and allow faster recovery from equipment or line failures.

That said, some line losses – such as those on the Aishihik -Takhini transmission line (L171) – are unavoidable due to the system’s geography and the Aishihik Generating Station’s role as a major winter renewable generation source.

In summary, while high-loss lines are recognized, Yukon Energy’s system planning approach focuses on strategic generation placement, targeted reliability upgrades, and deployment of new technologies which deliver greater value and flexibility than capital-intensive line twinning or reconductoring based solely on loss reduction.

(b)

The final line loss percentage for 2024 was 8.7%.

(c)

No, using the average of 2023 and 2024 actual line losses (both at 8.7%) would not provide a better predictor for line losses in the 2025–2027 test years than the currently forecasted 8.8%.

While 8.7% reflects recent measured outcomes, it does not capture the systemic challenges, variability, and contingency-driven dispatch decisions that influenced actual system flows – nor does it reflect potential future conditions that may drive line losses upward.

1 • **2024/2025 Conditions Were Operationally Constrained:**

- 2
- 3 ○ Aishihik generation was significantly reduced due to a low water year and
- 4 a 15 MW unit outage, leaving only 10–13 MW of available winter capacity
- 5 on average.
- 6
- 7 ○ The Takhini 8 MVar reactor was offline for 8 weeks in the late fall and early
- 8 2024 winter, limiting transmission north from Whitehorse and reducing
- 9 power flows, and therefore losses, on the Takhini–Carmacks and
- 10 Carmacks–Mayo corridors.
- 11
- 12 ○ A penstock failure at Mayo prevented up to 10 MW of hydro generation
- 13 from operating for 6–8 weeks during late fall and early 2024 winter.
- 14

15 These events happened in close timeframes and disrupted typical dispatch

16 patterns, resulting in islanding of the Faro system (running on local diesel backup),

17 while the Mayo–Dawson system operated on Dawson diesels and just 4.5 MW

18 from Mayo Hydro A. This system served multiple communities and industrial loads

19 (Dawson, Mayo, Keno, Victoria Gold, Hecla Mine, Stewart, Pelly, Minto, and

20 Carmacks) with constrained generation.

21

22 The net result was less energy transferred across long corridors and reduced

23 losses, but these conditions were atypical and not representative of future planning

24 assumptions.

25

26 • **Losses May Increase Under Normal or Stress Scenarios:**

27 With key infrastructure now restored, YEC expects system flow, and associated

28 losses, to increase relative to the constrained operating conditions in 2024:

29

- 30 ○ The Takhini 8 MVar reactor is back in service, enabling increased
- 31 northward transmission from Whitehorse and greater utilization of long
- 32 transmission corridors such as Takhini–Carmacks and Carmacks–Mayo.
- 33
- 34 ○ The Mayo penstock has been repaired, restoring full generation capacity
- 35 at the Mayo hydro facility, which supports power delivery across the
- 36 northern grid and southward exports when required.
- 37 ○ While Aishihik Generating Station remains a key source of dependable
- 38 winter renewable generation (up to 35.5 MW), another low water year is

1 forecast for 2025/2026, which may limit its ability to meet full winter
2 generation capacity.

3
4 Given this outlook, Yukon Energy anticipates that to meet Whitehorse's winter
5 load, particularly under growing demand due to electrification, the system will
6 require typical imports from Aishihik, Mayo, and Faro. These imports will
7 necessarily involve:

- 8
9
 - Long-distance power transfers on 138 kV lines such as L171 and L170,
10 which already represent the highest-loss corridors in the system, and
 - Greater reliance on long radial transmission, which increases both real and
11 reactive power losses.

12
13
14
15 As a result, system losses during the 2025–2027 test years are expected to reach
16 8.8% or higher, reinforcing the validity of the current forecast.

17
18 • **The 8.8% forecast:**

- 19
20
 - Matches the approved 2023/24 GRA value;
 - Reflects the 2022–2024 average (including a 9.0% result in 2022);
 - Provides headroom to accommodate operational variability and reliability
21 dispatch priorities.

22
23
24
25
26
27 This level of forecasted losses reflects not only historical average performance but
28 also the anticipated operational realities of the Yukon Energy grid as it returns to
29 full dispatchable capacity under a growing and more electrified load profile. The
30 8.8% forecast remains a more robust and representative planning assumption for
31 the 2025–2027 test years, accounting for system restoration, contingency
32 readiness, and future load growth.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 48, Footnote 12

2
3 **ISSUE:** Power Generation, renewables (non-hydro)

4
5 **QUOTE:** These IPP generation forecasts assume the currently connected seven
6 IPPs, five solar IPPs and two wind IPPs. The IPP supply forecast is
7 based on the LTA contract amounts signed with the IPPs. No other
8 IPPs are expected to be connected to the grid during the test years.

9
10 **QUESTION:**

- 11
12 a) Please explain why actual IPP purchase for 2024 were significantly less than
13 forecast.
14
15 b) With respect to footnote 12, what is the financial impact to YEC if an IPP does not
16 supply based on LTA? Does YEC pay the LTA amount to the IPP?
17
18 c) For micro-generators, should production from micro-generators be treated as an
19 offset to sales, or more precisely as a net sales figure? Please explain.
20
21 d) Please provide details on the IPP forecast by individual IPP, and the historical
22 output by individual IPP.

23
24 **ANSWER:**

25
26 **(a)**

27
28 The significantly lower actual IPP deliveries in 2024 were mostly due to later-than-
29 expected commercial operation dates (COD). For example, the 2023/24 GRA assumed
30 Takhini Power Corp's (Arctic Pharm) 2MW solar COD to be April 1, 2024, but the actual
31 COD was July 19, 2024. Similarly, Sunergy's 2 MW solar COD was assumed to be March
32 1, 2024, but the actual COD was May 29, 2024; and to a lesser extent, the COD for two
33 wind IPPs were eight days later than expected, with lower deliveries for the first month.
34 The IPP deliveries are also subject to weather conditions that impact the energy source
35 of the IPPs.

1 **(b)**

2
3 Yukon Energy's obligation to buy is limited to the energy volumes in Schedule B of the
4 Energy Purchase Agreements (EPA). Yukon Energy pays only for the delivered energy
5 plus any deemed energy payments related to non-permitted outages and curtailments
6 (constraints). If the delivered energy plus deemed energy payments are lower than the
7 EPA volume, then the power purchase cost would be lower than the forecast, with a
8 potential offset in the increased fuel cost. For example, in the 2023/24 GRA, Yukon Energy
9 estimated that IPPs displace about 59% thermal on a long-term average basis.

10
11 The LTA volumes for IPPs reflect energy volumes included in Schedule E of the EPAs,
12 where monthly projected energy volumes are provided for each IPP. Energy volumes in
13 Schedule E are the same as the maximum energy volumes in Schedule B, except for two
14 wind IPPs where the expected energy volumes in Schedule E are lower than the maximum
15 energy volumes in Schedule B [Haeckel Hill West Schedule E at 4.2 GWh vs Schedule B
16 at 5.4 GWh; Haeckel Hill East Schedule E at 4.0 GWh vs Schedule B at 5.2 GWh].
17 Therefore, the actual energy purchase volumes could be higher than the LTA volumes
18 included in the GRA, considering the maximum purchase obligations under the EPAs. In
19 this case, the power purchase cost would be higher than the forecast, with a potential
20 offset in the LTA thermal cost.

21
22 **(c)**

23
24 Yes, energy from micro-generators is treated as an offset to sales. The wholesale sales
25 forecasts reflect net of energy from micro-generators, i.e., i) total AEY grid load less ii)
26 AEY's own generation from Fish Lake hydro and any standby diesel, and less iii) any
27 energy supplied by micro-generators = AEY power purchases from Yukon Energy.

28
29 **(d)**

30
31 Please see the table below. Please note that 2025 will be the first year for some IPPs to
32 be in service for the whole year, i.e., the 2024 actual amount for four IPPs reflects partial
33 year results.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-26

MWh		COD	2023A	2024A	2025F	2026F	2027F
	Nomad (Mount Sima)	January 19, 2022	202	199	270	270	270
	Solvest/ North Klondike	November 16, 2021	1,510	1,560	1,840	1,840	1,840
	KDO Dawson Dome Road	March 2, 2022	252	261	280	280	280
	Haeckel Hill Wind East	March 8, 2024		2,567	4,205	4,205	4,205
	Haeckel Hill Wind West	March 8, 2024		2,375	3,995	3,995	3,995
	Sunergy	May 29, 2024		1,136	3,033	3,033	3,033
	Takhini	July 19, 2024		1,079	4,093	4,093	4,093
1	Total		1,964	9,177	17,717	17,717	17,717

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 49

2
3 **ISSUE:** Water Year Records

4
5 **QUOTE:** All remaining inputs are the same as in the 2023/24 GRA, including the
6 number of water year records [41 water years], license conditions and
7 flow restrictions.

8
9 **QUESTION:**

10
11 a) Please explain why the number of water year records has not changed since the
12 last GRA.

13
14 **ANSWER:**

15
16 **(a)**

17
18 There was insufficient time and available resources for Yukon Energy staff to update the
19 water years to include 2022-2024 water records to be used in the modelling. Considering
20 the low water conditions experienced in the 2023/24 and 2024/25, the potential impact of
21 including 2022-2024 water years would increase the long-term average thermal
22 generation.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 49

2
3 **ISSUE:** Fuel Mix (LNG versus Diesel)

4
5 **QUOTE:** It is assumed in the Application that 80% of LTA thermal generation
6 requirements as forecast for the test years will be met by LNG, with the
7 balance (20%) supplied by diesel generation.
8

9 **PREAMBLE:** The Board requires further information.

10
11 **QUESTION:**

12
13 a) What is the actual historical average for fuel mix (LNG:Diesel)?

14
15 b) If YEC was ordered by the Board to use the actual historical average for fuel mix,
16 please explain the impact of such a direction in terms of what is impacted and the
17 magnitude of that impact?

18
19 c) Is YEC forecasting any unique events in the GRA test years that can affect the
20 availability of either of the LNG or diesel units? Please explain.
21

22 **ANSWER:**

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

25
26 Table 3.3-1 in Appendix 3.3 of the Application provides the historical fuel mix (2016-2024),
27 with the average of 70% LNG and 30% diesel. This average only reflects the YIS load and
28 water availability conditions in these nine years – it does not reflect any assessment of
29 LTA fuel mix based on GRA forecast loads and available LTA water availability over 41
30 water years of current information.
31

32 Table 3.3-2 in the same appendix provides the impact of the 80% LNG/20% diesel
33 proposed by Yukon Energy [\$0.471 million increase in fuel costs compared to 90/10, or
34 approximately 0.3% rate impact], as well as the impact of the 70% LNG/30% diesel
35 historical average [\$0.942 million increase in fuel costs compared to 90/10, or
36 approximately 0.6% rate impact]. The revenue requirements in the Application assumes
37 80% LNG and 20% diesel. A Board direction to use the nine-year existing historical

1 70%/30% LNG/diesel mix would not consider the extent to which this nine-year period
2 does not reflect the available LTA evidence on below average water availability including
3 prolonged periods of drought conditions (with related increases in LNG generation in the
4 fuel mix). The blended fuel mix required to be used for GRA purposes should reflect, to
5 the extent practical, information on LTA water availability as well as the forecast load
6 requirements.

7
8 **(c)**
9

10 Yukon Energy is not forecasting any unique events during the GRA test period that can
11 affect the availability of LNG or diesel units that would significantly impact the LTA fuel
12 mix. Although any unplanned issues that occur during the GRA test period could impact
13 the availability of these units, they do not impact the revenue requirements in this
14 Application.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 49

2
3 **ISSUE:** Thermal Generation Unit Operations

4
5 **QUOTE:** In addition to the thermal generation forecast to supply required firm
6 loads, Yukon Energy is including in its forecast expenses in this
7 Application (see Tab 3) forecast thermal unit operation for maintenance
8 when there is no firm generation load that requires thermal generation.
9 These requirements exist separate from the LTA thermal requirements
10 as estimated above and in Table 2.2. To ensure proper maintenance
11 and reliability, the diesel and LNG units need to be run at certain times
12 solely for maintenance purposes, especially during the summer
13 months.
14

15 **QUESTION:**

- 16
17 a) Please explain how summer thermal operations described above affect the
18 determination of amounts for the LWRF.
19

20 **ANSWER:**

21
22 **(a)**

23
24 The summer thermal operations described above are primarily non-fuel O&M costs related
25 to thermal generation monthly run-ups, or maintenance activities. It is best practice for
26 generators to not sit unused for too long in order to minimize the risk that generators will
27 not work when needed for generation purposes.
28

29 As per the approved LWRF Term Sheet, non-fuel O&M costs related to thermal generation
30 are not included in the LWRF calculations. Non-fuel O&M costs, or summer thermal
31 operations described above, are noted in relation to the LTA thermal requirements as the
32 LWRF calculation starts with total thermal generation and then deducts the non-fuel O&M
33 costs. This results in avoidance of duplication of these costs. Non-fuel O&M costs related
34 to thermal generation are included in Tab 3 (see Total Maintenance of \$0.011 million for
35 each of 2025, 2026 and 2027 in Table 3.2.1 of the Application) and not in the LWRF
36 calculation of LTA thermal requirements.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 50

2
3 **ISSUE:** Peak Demand Forecast

4
5 **QUOTE:** Yukon Energy continues to communicate with relevant stakeholders in
6 order to ensure the load forecasts are based on currently available
7 information.

8 ...
9 The peak forecasts were developed using an econometric model that
10 considers wide-range projections [i.e., other stakeholder inputs].

11
12 **PREAMBLE:** The Board seek further information.

13
14 **QUESTION:**

15
16 a) Please list the relevant stakeholders alluded to in the first quote. Please provide
17 the criteria that makes those stakeholders relevant.

18
19 b) For the second quote please list and describe the other stakeholder inputs, and
20 the impact those inputs had in developing the peak demand forecast.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Yukon Energy worked with AEY as well as with major industrial customers during the
27 preparation of the load forecasts in the current Application. Yukon Energy's firm sales are
28 primarily made up of firm wholesale sales to AEY, representing about 80.0% of sales for
29 the 2025-2027 test years. Similarly, although the industrial peak demand does not impact
30 N-1 capacity shortfall calculations, they are the single largest customers with the highest
31 usage per customer base. Therefore, discussions with the industrial customers are also
32 relevant.

33
34 **(b)**

35
36 The peak forecasts for non-industrial customers were developed using an econometric
37 model that considers wide-range projections with inputs from other stakeholders, e.g.,

Yukon Government, Yukon Bureau of Statistics and City of Whitehorse. For example, assumptions about economic activity, such as population, households, and Gross Domestic Product statistics, were utilized in an economic model developed in collaboration with the Yukon Government's Department of Energy Mines and Resources, Yukon Bureau of Statistics, City of Whitehorse, and Itron (energy consultant). Yukon Energy uses these inputs and the economic model to estimate impact on customer counts and sales projections, which in turn drive the non-industrial peak demand forecast.

Prior to filing the Application, the last update of the econometric model was completed by Itron for the 10-Year Renewable Electricity Plan in 2019. The model captured a range of input data from 2008 to 2018, including historical sales and energy data by customer class from 2008 to 2018, economic activity forecasts, population projections, average expected weather conditions, electricity prices, and improvements in end-use efficiency and standards. The output from the model was then adjusted for additional loads that were not captured in the output, including incremental loads from specific climate policy incentives such as the adoption of electric vehicles and heat pumps in buildings. Since 2019, Yukon Energy has re-calibrated the peak forecast using actual recorded peak data to align with observed population growth and end-use patterns.

Given the recent higher growth seen in population and electricity sales, the econometric model was updated by Itron in July 2025, after the current GRA was filed. The updated forecast non-industrial peak on the YIS for winter 2025/26 is 1.3 MW higher, 2026/27 winter peak 4.4 MW higher and 2027/28 winter peak is 6.7 MW higher than the forecast included in the Application.

The following table shows the updated non-industrial peak demand as well as capacity shortfalls based on the updated demand forecasts [updated version of the table provided on page 2-16 of the Application].

in MW		2025/26	2026/27	2027/28
A	Non-industrial peak under N-1	121.9	129.8	136.1
B	Dependable capacity under N-1	88.6	94.2	94.4
C=B-A	Capacity shortfall under N-1	-33.3	-35.6	-41.8
D	Diesel rentals=22 units each unit at 1.53 MW	33.7	33.7	33.7
E=C+D	Capacity (Shortfall)/Surplus with diesel rentals	0.4	-1.9	-8.1

1 The updated forecast now shows a 1.9 MW incremental capacity shortfall in 2026/27 and
2 an 8.1 MW capacity shortfall in 2027/28, even after 22 rentals. The key changes were
3 predominantly related to the electrification of heating, improvements in building energy
4 and envelope efficiency, electric vehicle uptake as well as a change in the design
5 temperature from -39 degrees C to -40 degrees C, which is the coldest average
6 temperature in the last 10 years. Please see the response to YUB-YEC-1-9 a) and b) for
7 the details on how Yukon Energy is planning to address these increased capacity
8 shortfalls.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 51, footnote 15

2
3 **ISSUE:** Loss of Load Expectation (LOLE)

4
5 **QUOTE:** However, the Board in its report to the Yukon government on the 2006
6 Resource Plan recommended that “to ensure that no new generating
7 capacity is added for the purpose of ensuring reliable supply to major
8 industrial customers and to ensure consistency with the N-1 criterion,
9 major industrial loads should not be included in the LOLE calculation.”
10 Although the 2011 and 2016 updates to the resource plan also
11 assumed industrial load in the LOLE, consistent with the initial
12 assessments, to date, the LOLE criterion has not been the driving factor
13 in the capacity shortfall calculations, therefore, the issue of inclusion or
14 exclusion of the industrial load was never raised.

15
16 **QUESTION:**

- 17
18 a) Please explain what is meant by, “the LOLE criterion has not been the driving factor
19 in the capacity shortfall calculations; therefore, the issue of inclusion or exclusion
20 of the industrial load was never raised.” Does this mean that YEC is applying an
21 LOLE criterion that is not authorized in the Board’s 2006 recommendation?

22
23 **ANSWER:**

24
25 **(a)**

26
27 To respond to this question, Yukon Energy’s criteria since 2006 for determining
28 dependable capacity requirements are reviewed below.

29
30 Yukon Energy uses two planning criteria when determining dependable capacity needs:
31 N-1 and LOLE, as detailed on page 2-13 in Tab 2. The LOLE is a probabilistic-based
32 measure to evaluate maximum loads that the hydro grid (WAF and MD grids earlier, YIS
33 today) can safely carry. The N-1 criterion is an added criterion, described as an
34 Emergency Standard for protection against prolonged disruption, which determines
35 system capacity assuming loss of the system’s single largest generating or transmission-
36 related generation resource. Yukon Energy’s dependable capacity requirement is
37 determined based on the maximum resulting from applying both of these planning criteria.

1 To date, the N-1 criterion, which focuses on non-industrial peak for capacity shortfall
2 requirements, has been more stringent and used for identifying the need for diesel rentals
3 or other resources of firm dependable capacity in each of Yukon Energy's previous GRAs
4 since 2006, including this 2025-2027 GRA.

5
6 The LOLE criterion in Yukon Energy's GRAs since 2006, on the other hand, has included
7 industrial loads as part of the assessment. This was noted in each of the previous GRAs
8 [for example, 2023/24 GRA, Tab 2, page 2-13]. GRAs immediately following the 2006
9 Resource Plan re-iterated regulatory principles supporting the inclusion of industrial loads
10 as part of the LOLE criterion assessment, contrary to the YUB's recommendation to the
11 Yukon government, including providing support for industrial firm rates being based on
12 these customers being included in the grid dependable capacity requirement
13 assessments.

14
15 In summary, the LOLE criterion has not been the driving factor in the capacity shortfall
16 calculations for each GRA since 2006 even with industrials being included, i.e., the LOLE
17 criterion would be further reduced if industrials were excluded. Therefore, the issue of
18 inclusion or exclusion of the industrial load was never reviewed as a factor determining
19 the dependable capacity requirement for any GRA to date.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 53

2
3 **ISSUE:** Effective Load carrying Capacity, Diesel Rentals, Forced Outage Rates
4 (FOR)

5
6 **QUOTE:** ELCC for thermal units - A FOR of 10% is conservatively assumed for
7 all AEY diesel units connected to the YIS. For diesel rental units, a FOR
8 of 15% has been assumed to reflect reliability experience with those
9 units.

10
11 **QUESTION:**

12
13 a) How was the AEY thermal units FOR derived and determined?

14
15 b) For rental diesel units the FOR is higher. Given this higher FOR, why hasn't YEC
16 created a plan to replace all rental units with its own thermal generating units?

17
18 **ANSWER:**

19
20 **(a)**

21
22 For the diesel generators owned and maintained by AEY in the Yukon communities that
23 are connected to the Yukon Integrated System, an industry-standard ELCC of 90% is
24 assumed based on the 5-year weighted forced outage rate of about 10% for conventional
25 generation (gas, diesel, oil, or coal) published by North American Electric Reliability
26 Corporation (NERC).¹ The data from NERC includes forced outage rates for thermal units
27 operated by utilities across North America.

28
29 **(b)**

30
31 Yukon Energy's requirement to use rental diesel units is determined by factors not
32 involving the FOR impacts, and is proceeding to develop significant increases in
33 permanent thermal capacity to meet rapid growth in winter peak loads without relying on
34 diesel rentals. Please see the response to YUB-YEC-1-8, which also provides update on
35 the Whitehorse Power Centres Project.

¹ North American Electric Reliability Corporation [NERC] (2024). 2024 State of Reliability.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 60. Footnotes 3

2
3 **ISSUE:** Expected Thermal Generation

4
5 **QUOTE:** The model calculates expected hydro plant generation for each load
6 scenario. It incorporates, on a weekly time step, 41 "water years" on
7 record (1981-2021) and 20 "load years" (each examines a different
8 hypothetical scenario to evaluate generation under different sequences
9 of the recorded water years), of which 13 load years (load years 7-19)
10 are used for the final averaging (this removes results distorted by
11 starting or ending year volumes). "Hydro Generation" is long-term
12 average hydro generation as estimated by YECSIM.

13
14 **QUESTION:**

- 15
16 a) Why does the model not include water years 2022-2024? Please explain.
17
18 b) Regarding the 20 load years, are these real loads or hypothetical loads for testing
19 purposes? Please explain.
20
21 c) If applicable, do the load years match the water years? Please explain.
22

23 **ANSWER:**

24
25 **(a)**

26
27 Please see the response to YUB-YEC-1-27.
28

29 **(b) and (c)**

30
31 The model uses forecast loads [i.e., 2025 forecast load under all 20 "load years"] to
32 determine the long-term average (LTA) hydro generation, i.e., the model does not use
33 hypothetical loads unrelated to the GRA test years.
34

35 For Table 2.1-1 in Appendix 2.1, the range of loads was used to determine the LTA hydro
36 generation for each given load level assumed in the table [for example, a 480 GWh load
37 was used under all 20 "load years" to determine the LTA hydro generation for the 480
38 GWh load, etc.].

1 The model uses the recorded sequences of river flows (termed “water years”) and
2 superimposes them over the projected load being analyzed (termed “load years”). Each
3 combination of a sequence of “water years” and “load years” constitutes a “cycle”. The
4 “water years” are then shifted by one year and superimposed on the “load years” again,
5 and this process is repeated over 20 “load years”. This provides the hypothetical scenario
6 of energy generation capability that would occur if the recorded series of “water years”
7 would repeat itself.

8
9 Out of 20 “load years”, 13 load years (load years 7-19) are used for the final averaging.
10 This deletes cases where the starting or ending year volumes can potentially distort
11 results.

12
13 These modelling methods were reviewed in the previous proceedings, including DCF-ERA
14 proceeding as well as part of the 2017/18 GRA.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 59

2
3 **ISSUE:** Fish Lake Hydro

4
5 **QUOTE:** The forecast LTA thermal generations are 63.857 GWh for 2025,
6 70.926 GWh for 2026 and 78.405 GWh for 2027 based on Table 2.1-1
7 developed to determine annual expected YEC thermal generation
8 based on long-term average YEC hydro generation at YEC forecast
9 grid loads (net of IPPs and Fish Lake generation) ranging from 480 to
10 580 GW.h/year.

11
12 **PREAMBLE:** The Board seeks further information.

13
14 **QUESTION:**

- 15
16 a) Please provide the amount of forecast Fish Lake Hydro generation for each of the
17 test years.
18
19 b) How did YEC determine the forecast Fish Lake Hydro production for each of the
20 test years?
21
22 c) Do the IPPs referenced above pertain only to IPPs directly connected to the YEC
23 system? Please explain.
24
25 d) Later in the paragraph, YEC states, “One table was developed for all three test
26 years considering no change in the IPP deliveries and similar load shape.” How
27 valid is this assumption? Please explain.
28

29 **ANSWER:**

30
31 **(a) and (b)**

32
33 YEC does not have specific Fish Lake Hydro generation forecasts for its GRA submission,
34 i.e., the AEY wholesale forecasts provided for YEC adoption already had removed the
35 impacts of AEY’s assumed Fish Lake Hydro generation. This is reviewed below in more
36 detail.

1 AEY's Fish Lake impacts Yukon Energy in two ways:

- 2
- 3 • The amount of wholesale sales to AEY; and
- 4 • Fish Lake generation for the LWRF purposes.
- 5

6 Each of these are explained in further detail below. In essence, however, the two factors
7 are interrelated, i.e., Fish Lake generation reduced the amount of wholesales to AEY.

8

9 **Fish Lake Hydro impact on wholesale sales to AEY**

10

11 Yukon Energy does not have specific information on Fish Lake Hydro generation forecasts
12 assumed by AEY for the 2025-2027 years in preparation of the AEY power purchase
13 forecasts for the 2025-2027 years. As indicated in response to YUB-YEC-1-87, AEY's firm
14 power purchases from Yukon Energy are the result of the total AEY grid load, less AEY
15 Fish Lake generation, less AEY grid standby diesel generation, and less micro-generation.
16 In this sense, the power purchase forecasts provided by AEY for this GRA are already net
17 of Fish Lake generation. For purposes of calculating the revenue requirements for the
18 2025-2027 test years, Yukon Energy has continued to assume wholesale forecasts as
19 provided by AEY.

20

21 **Long-term average (LTA) Fish Lake generation**

22

23 Yukon Energy understands that OIC 2021/16 now requires the use of LTA for any
24 renewable generation forecasts in a Yukon Energy GRA, and that this requirement
25 includes the use of Fish Lake hydro forecasts used to forecast AEY power purchases from
26 Yukon Energy that directly impact the forecast of Yukon Energy forecast generation and
27 related forecast thermal generation for test year revenue requirements.

28

29 As noted in Board Order 2025-08, the last approved Fish Lake LTA was from Board Order
30 2014-06. Section 3.2 Views of the Board in the Board Order 2014-06 stated, "Considering
31 the long-term averages submitted by YECL and the lack of clarity respecting the efficiency
32 gains related to the installation of new equipment, the Board for purposes of this
33 application accepts the 8.73 GW.h annual generation output for the test period." In Board
34 Order 2024-01, as part of AEY's 2023/24 GRA, the Board quoted Yukon Energy's
35 comment in paragraph 35 "...YEC...concluded by stating that it forecasts Fish Lake hydro
36 generation at 8.7 GWh for each test year equal to the long-term average (LTA), as required
37 by OIC 2021/16." Board Order 2024-01 accepted a test-year Fish Lake forecast but made

1 no mention of a change in Fish Lake LTA. Furthermore, during the AEY 2023/24 GRA it
2 was disclosed that hydrogeneration in any particular year can be impacted by planned
3 maintenance, water availability and adjusted for any planned decreases due to capital
4 rebuilds [for example, the forecast Fish Lake generation in AEY's 2023/24 GRA
5 Compliance filing was 7.8 GWh for 2023 and 10.1 GWh for 2024].

6
7 Therefore, Yukon Energy interpreted all the above in its 2023/24 GRA to mean that there
8 has been no change in 'approved' LTA Fish Lake generation from the amount approved
9 in Board Order 2014-06, notwithstanding ongoing changes affecting Fish Lake operation.

10
11 Yukon Energy has no new information today to assess separately any updated LTA for
12 Fish Lake hydro, therefore, for this GRA purposes, no changes are assumed in the LTA
13 for Fish Lake as approved by Board Order 2014-06.

14
15 **(c)**

16
17 Confirmed, the IPPs referenced in the LTA thermal generation calculations pertain only to
18 IPPs with which Yukon Energy has Energy Purchase Agreements and are forecast to be
19 connected to the YIS during the GRA test years.

20
21 **(d)**

22
23 In Appendix 2.1 of the Application, Yukon Energy proposed one table for calculating the
24 LTA thermal generations [Table 2.1-1] for various potential YEC loads for 2025, 2026 and
25 2027 test years based on long-term average hydro generation. This is a valid assumption
26 considering that there are no changes in the LTA IPP deliveries for all three test years
27 [i.e., all three test years have LTA IPP deliveries at 17.7 GWh as reviewed in Table 2.2]
28 and have similar load shape considering the same industrial load forecasts for all test
29 years. Any separate table developed for each test year would have similar outcomes,
30 based on these factors remaining the same for each test year. Therefore, one table for all
31 three years is a reasonable approach for calculating the LTA thermal generation
32 requirements for various potential YEC generation loads.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 64-65 and Table 3.2

2
3 **ISSUE:** Fuel and Purchased Power

4
5 **PREAMBLE:** Actual 2023 and 2024 fuel costs are significantly lower than approved
6 2023 and 2024 fuel costs. Similar for 2024 purchased power costs.
7

8 **QUESTION:**
9

- 10 a) Please explain why 2023 and 2024 fuel costs are less than forecast.
11
12 b) Please explain why 2024 purchased power costs are less than forecast.
13
14 c) Please provide a revised Table 3.2 with final 2024 actual values.
15
16 d) In Section 3.2.1 Fuel costs, the last sentence of the first paragraph states: "The
17 proposed test year fuel costs also include requirements for thermal facility fuel use
18 for maintenance." In prior GRAs, was thermal facility fuel use for maintenance
19 included in forecast fuel costs? Please explain.
20
21 e) In Section 3.2.1 Fuel costs, the last sentence of the second paragraph states: "The
22 fuel cost for forecast long-term average thermal generation is \$16.8 million in 2025,
23 \$18.7 million in 2026 and \$20.6 million in 2027 before considering forecast fuel
24 costs for thermal maintenance activities." The first paragraph states fuel
25 maintenance costs are included in the forecast. The second paragraph states the
26 costs as described are before fuel maintenance costs. Which is the correct
27 statement? Please explain.
28
29 f) On PDF page 65 YEC states: "For maintenance activities, the forecast diesel is
30 0.021 GWh/year and LNG is 0.017 GWh/year for total cost of \$0.011 million/year
31 compared to \$0.061 million in the 2023/24 GRA." Please explain why fuel costs for
32 maintenance activities have decreased for the current test years relative to the
33 previous test years of 2023 and 2024.
34
35 g) Relative to part (e), Please explain the reduction in MW.h for diesel run-ups 2025-
36 2027 test years versus 2023-2024 approved.

1 h) Similarly to the above question, please explain the increase in MW.h for LNG run-
2 ups 2025-2027 test years versus 2023-2024 approved.

3
4 **ANSWER:**

5
6 **(a)**

7
8 Please see YUB-YEC-1-35 Attachment 1 for the updated actual fuel costs for 2024.

9
10 The actual fuel costs for 2023 were \$14.367 million compared to \$15.748 million approved
11 for 2023 in the 2023/24 GRA. The variance of -\$1.381 million is due to the following:

- 12
- 13 • At the time of finalization of the 2023 Financial Statements, the 2023/24 GRA final
14 order was not issued, and the new fuel prices proposed for 2023 were not yet
15 approved. Therefore, the 2023 results were finalized based on the latest approved
16 fuel prices at that time, which were based on the 2021 GRA. The recalculated fuel
17 expense using the 2023/24 GRA inputs resulted in a \$1.2 million higher fuel cost
18 for 2023 as detailed in the 2023/24 GRA Compliance Filing Table 1.1-6 [i.e., Table
19 3.2 understates the fuel cost for 2023 by about \$1.2 million as the new approved
20 fuel prices were not available at the time of audit].
 - 21
 - 22 • Lower than forecast load for 2023 also resulted in a lower than approved fuel cost.
- 23

24 The actual fuel costs for 2024 as updated in this response were \$15.414 million compared
25 to \$15.295 million approved for 2024 in the 2023/24 GRA. The variance of \$0.199 million
26 is due to the following:

- 27
- 28 • The share of diesel in the total thermal generation for 2024 was much higher
29 compared to the 90/10 mix assumed in the GRA. As detailed in the 2024 LWRF
30 filing, the actual share of net diesel in the total thermal generation was about 43%
31 compared to 10% assumed in the GRA. As the diesel cost per kWh is higher than
32 the LNG cost, the higher percentage share of diesel generation resulted in a higher
33 fuel cost, offsetting any fuel cost savings from lower loads.
- 34

35 **(b)**

36
37 The actual power purchase costs for 2024 are lower than approved costs due to delays
38 with the commercial operation dates for IPPs. Please see the response to YUB-YEC-1-26

1 (c)

2
3 Please see YUB-YEC-1-35 Attachment 1.
4

5 (d), (f), (g) and (h)
6

7 Yes, the fuel for maintenance run-ups was included in forecast fuel costs in 2017/18 GRA,
8 2021 GRA and 2023/24 GRA. The diesel and LNG units need to be run at certain times
9 solely for maintenance purposes, especially during the summer months. In these
10 circumstances, the fuel requirements for electricity generated for maintenance will be part
11 of the operating expense requirements but not part of the LTA generation requirements.
12 Therefore, the fuel costs for maintenance run-ups are included as part of the total fuel
13 costs.
14

15 The approved fuel costs for maintenance run-ups in 2023 and 2024 were \$0.061 million
16 for each test year based on a 198 MWh diesel generation forecast; no maintenance run-
17 ups for LNG were included. For the 2025-2027 test years, the forecasted cost is \$0.011
18 million/year, reflecting forecast diesel generation of 21 MWh and LNG generation of 17
19 MWh for maintenance run-ups. The reduction in diesel kWh for maintenance run-ups
20 reflects the lower actuals [2023 was at 78 MWh and 2024 at 35 MWh], and the addition of
21 LNG maintenance run-ups reflects the fact that LNG units also need to be run for
22 maintenance. Overall, the proposed total cost of \$0.011 million/year is not significant and
23 remains lower than approved maintenance fuel costs for 2023 and 2024.
24

25 (e)
26

27 The referenced sentences are both correct.
28

29 Table 3.2.1 of Tab 3 provides details of the calculation of the fuel costs, which includes
30 the cost related to long-term average thermal generation as well as the cost of fuel for
31 maintenance run-ups. Accordingly, lines 18 through 22 on page 3-3 of Tab 3, discuss the
32 cost related to long-term average thermal generation prior to addition of the fuel cost for
33 maintenance run-ups, while lines 23 through 24 on page 3-3, and lines 1 through 3 on
34 page 3-4 discuss the cost of fuel for maintenance run-ups.

Yukon Energy 2025-27 GRA
YUB-YEC-1-35 Attachment 1

Table 3.2
Fuel and Purchased Power
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Fuel	\$ 15,748	\$ 15,295	\$ 14,367	\$ 15,414	\$ 16,802	\$ 18,661	\$ 20,627
Purchased Power	380	2,759	368	1,733	3,435	3,469	3,504
Total Fuel and Purchased Power	<u>\$ 16,128</u>	<u>\$ 18,054</u>	<u>\$ 14,736</u>	<u>\$ 17,147</u>	<u>\$ 20,237</u>	<u>\$ 22,130</u>	<u>\$ 24,131</u>

Note:

1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance requirements, and forecast fuel prices.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 66

2
3 **ISSUE:** LNG supply

4
5 **QUOTE:** Direct negotiations with one LNG supplier were initiated because of the
6 evolving LNG supply landscape, recognizing limited competition and
7 supply constraints in the region.

8
9 **QUESTION:**

10
11 a) What is the term of the Cryopeak Energy Solutions LNG Supply Agreement that
12 was effective December 1, 2024?

13
14 b) For the previous LNG supply agreement, where was the source of the supply
15 (geographic region)?

16
17 **ANSWER:**

18
19 **(a)**

20
21 The initial term of the agreement commenced on December 1, 2024, and terminates on
22 December 31, 2028, with an option for Yukon Energy to extend for an additional one-year
23 term.

24
25 **(b)**

26
27 The supply source was not specified in the contract.

28
29 The previous LNG supply agreement in 2019 was with Ferus, who only had a
30 manufacturing facility in Elmworth, Alberta. However, terms of the contract allowed Yukon
31 Energy to buy from other vendors, such as from Campus Energy who had a manufacturing
32 facility in Dawson Creek, British Columbia and Cryopeak Energy Solutions, who had a
33 manufacturing facility in Fort Nelson, British Columbia. In February 2024, Ferus merged
34 with Campus Energy and Cryopeak, the party now contracted with YEC. Cryopeak Energy
35 Solutions may supply Yukon Energy with product from any of its manufacturing facilities,
36 which because of the merger remain in Fort Nelson, British Columbia, Dawson Creek,
37 British Columbia and Elmworth, Alberta. Typically, Cryopeak tries to source from its Fort
38 Nelson facility as that location is the closest facility to Whitehorse.

REFERENCE: YEC 2025-2027 Application, PDF page 69

ISSUE: O&M Labour – Labour escalators

QUOTE:

3.3.1 Labour

Total labour expenditure is made up of labour expense for maintenance and administration and capitalized labour. Capitalized labour is charged to capital projects rather than O&M expenses. It becomes part of revenue requirement through annual depreciation charges incurred after in-service of the related project. Maintenance and administration labour expense is charged directly to revenue requirement. Total maintenance and administration labour expense is forecast to be \$18.0 million in 2025 as compared to 2024 approved costs of \$16.1 million, increasing to \$19.5 million in 2026, and \$20.6 million in 2027.

Labour expense is generally a function of the following factors:

- **Labour Rates** – This includes factors such as base pay, benefit cost, and annual increments (performance increments, cost of living adjustments). This is heavily influenced by collective bargaining agreements (CBA). The current CBA expires December 31, 2025. Labour rates for 2025 are based on the current CBA. Negotiations for the CBA effective January 1, 2026 are expected to start in Q4 of 2025. Forecast 2026 and 2027 labour rates are estimated to reflect an inflationary increase of 2.00%. It is estimated that the new agreement will be finalized in late 2025 or early 2026.
- **Head Count** – This relates to the number of full time equivalent (FTE) positions. The Yukon Energy employee complement is shown in Table 3.4.

QUESTION:

- a) Please provide the labour escalation being applied to YEC's out-of-scope employees for each of 2025-2027 test years and explain how this per cent was determined and why it is relevant in the circumstances of the current application.
- b) Please provide details with respect to the Yukon government wage rate adjustments for the years 2025-2027 and whether it is relevant in the circumstances of the current application.
- c) For each year identified, please calculate an average cost per employee on an: approved basis for 2023-2024; actual basis for 2023-2024; and forecast basis for

1 2025- 2027. What factors does YEC attribute to any variances noted for each year
2 (actuals 2023, 2024, approved 2023, 2024 and forecast 2025, 2026, 2027)
3 between the numbers being calculated in its response to this IR.

4
5 d) With respect to non-labour O&M and capital costs, has YEC used any type of
6 escalation or inflation factor for forecasting purposes? Please provide the per cent
7 factor incorporated in YEC's 2025-2027 revenue requirement

8

9 **ANSWER:**

10

11 **(a)**

12

13 The labour escalation being applied to Yukon Energy's out-of-scope employees for 2025
14 was 3.00%, as approved by the Board of Directors of Yukon Energy on November 8, 2023.
15 The rate was set to equal the same rate for in-scope employees as per the 2023-2025
16 Collective Bargaining Agreement.

17

18 For 2026 and 2027, the labour escalation being applied to Yukon Energy's out-of-scope
19 employees is 2.00%, the same increase estimated for in-scope employees. To keep pace
20 with current market labour conditions, Yukon Energy estimated the rate of increase at the
21 assumed rate of inflation expected. While recent years have resulted in inflation greater
22 than 2.00%, the general consensus is that inflation will return to its historical average of
23 approximately 2.00%.

24

25 Labour rates for out-of-scope employees are relevant in all general rate applications,
26 including the current application, as Yukon Energy must recover costs of all employees,
27 not just in-scope employees.

28

29 **(b)**

30

31 Yukon Energy typically uses Yukon Government wage rate changes as guidance for
32 negotiations with the Union for Yukon Energy employees, so typically this information
33 would be relevant. However, for the current application, this information is not yet available
34 as the Yukon Government is still in contract negotiations with its union for the calendar
35 years of 2025, 2026 and 2027. Details of Yukon Government wage negotiations are not
36 available to Yukon Energy.

As the Yukon Government wage rate changes were not available to provide guidance, Yukon Energy used inflation estimates as a reference for the current application.

(c)

Average cost per employee has been calculated using labour cost (both labour expense and capitalized labour) divided by the employee complement (number of full-time equivalent employees).

	2023 Approved	2023 Actual	2024 Approved	2024 Actual	2025 Forecast	2026 Forecast	2027 Forecast
Labour Cost (\$000's)	\$ 18,362	\$ 18,330	\$ 19,651	\$ 21,990	\$ 22,812	\$ 24,943	\$ 26,296
# of FTE's	113.05	113.66	119.81	123.46	128.94	139.84	144.44
Average Cost per Employee (\$000's)	\$ 162	\$ 161	\$ 164	\$ 178	\$ 177	\$ 178	\$ 182

The most significant factor that stands out in the data is the variance between 2024 actual labour costs and 2024 approved costs. The variance is primarily due to the amount of overtime as shown below.

	2023 Approved	2023 Actual	2024 Approved	2024 Actual	2025 Forecast	2026 Forecast	2027 Forecast
Overtime (\$000's)	\$ 866	\$ 1,240	\$ 775	\$ 1,688	\$ 1,262	\$ 1,201	\$ 1,171
Average Overtime per Employee (\$000's)	\$ 7.663	\$ 10.913	\$ 6.465	\$ 13.672	\$ 9.790	\$ 8.590	\$ 8.105
Change in Overtime per Employee (%)				25%	-28%	-12%	-6%

During the 2023/24 application preparation process, Yukon Energy attempted to minimize rate impacts but was too conservative with estimating the amount of workload that would be required in 2024. The 2025 Forecast average labour cost per employee is significantly greater than 2024 approved, reflecting the actual increase in cost from 2023 to 2024. During the 2025-27 application preparation process, Yukon Energy has again attempted to minimize rate impacts by assuming a decrease in overtime per employee.

However, significant deviations from the Application have also developed in 2025 and are also expected to impact 2026 and potentially 2027 costs. In Yukon Energy's Application, forecasts for 2025 through 2027 were based on a relatively normal level of diesel generation and a normal vacancy factor.

- i. Due to low water levels and a low snowfall in winter 2024/25, diesel generation in 2025 greatly exceeded expectations. As a result, Yukon Energy incurred a significant amount of overtime to run and maintain the diesel engines. To June 30,

2025, Yukon Energy's diesel generation exceeded its planned diesel generation by 116%. The additional hours running the diesel engine resulted in additional labour expenses, including additional overtime, of \$650,000 more than budgeted. Due to current exceptionally low water levels at Aishihik, this trend is now expected to continue into 2026, and potentially 2027.

- ii. As shown in YUB-YEC-1-38(b) and (c), Yukon Energy's vacancy factor to June 30, 2025 of 5.01 is significantly less than the five-year average of 9.91, resulting in a higher forecast labour expense in 2025 by approximately \$250,000 (net of assumed lower overall overtime).

Yukon Energy's forecast labour cost included in the Application was based on the best information available at the time. However, as Yukon Energy has incurred additional labour expenses due to higher diesel generation requirements and a low vacancy factor, labour costs for 2025 are now forecast to be significantly different than submitted in the Application. The below compares the updated forecasts to the Application. The forecast for 2026 has also been updated to reflect expected higher diesel generation requirements.

(\$000's)	2025	2026	2027
Updated Forecast	\$ 18,904	\$ 20,176	\$ 20,597
Application Forecast	\$ 18,005	\$ 19,530	\$ 20,597
Difference	\$ 899	\$ 646	\$ -

(d)

With respect to non-labour O&M costs, as stated in the application on PDF page 69, "Yukon Energy and the Yukon have experienced, and are expected to continue to experience, inflation in the test years. Inflation is assumed to reduce to historical levels of approximately 2%. As this is a three-year GRA, Yukon Energy has assumed future test year (2026 and 2027) costs would increase by 2%, if applicable. For example, where contracts exist, no additional future year adjustments for inflation has been made."

The following are examples of non-labour O&M costs where no generic escalation or inflation factor was used:

- Fuel;
- Purchased power;

- Brushing;
- Transportation fuel;
- Union;
- Regulatory affairs; and
- Capital project studies.

With respect to capital costs, Yukon Energy did not use any type of escalation or inflation factor.

While the question only asked about non-labour O&M escalation factors affecting costs in 2026 and 2027, significant deviations from the Application have developed in 2025 and are also expected to impact 2026 non-labour O&M expenses.

As described in part (c) above, in Yukon Energy's Application, forecasts for 2025 through 2027 were based on a relatively normal level of diesel generation. However, due to low water levels and a low snowfall in winter 2024/25, diesel generation in 2025 greatly exceeded expectations. As a result, Yukon Energy incurred a significant amount of overtime to run and maintain the diesel engines. To June 30, 2025, Yukon Energy's diesel generation exceeded its planned diesel generation by 116%. The additional hours running the diesel engine resulted in additional diesel expenses, such as consumables that are based on runtime hours, of \$650,000 more than budgeted. Due to current exceptionally low water levels at Aishihik, and updated inflow forecasts that show 40% lower than normal, this trend is now expected to continue into 2026, and potentially 2027.

Yukon Energy's forecast diesel maintenance cost included in the Application was based on the best information available at the time. However, as Yukon Energy has incurred additional diesel maintenance expenses due to higher diesel generation requirements, diesel maintenance costs for 2025 are now forecast to be significantly different than submitted in the Application. The below compares the updated forecasts to the Application. The forecast for 2026 has also been updated to reflect expected higher diesel generation requirements.

(\$000's)	2025	2026	2027
Updated Forecast	\$ 1,311	\$ 1,355	\$ 717
Application Forecast	\$ 655	\$ 699	\$ 717
Difference	\$ 656	\$ 656	\$ -

In addition to changing forecasts for diesel maintenance costs, non-labour O&M costs are also forecast to be different from the Application with regard to diesel rental costs. In Yukon Energy's Application, Yukon Energy stated, "Yukon Energy is currently negotiating the diesel rental contract for the period that commences after expiry of the current contract in April 2025."¹ Assumptions were made as to what the terms of the new contract would entail. As a result of negotiations with the vendor, Yukon Energy agreed to a two-year contract at total costs that were different from what was included in the Application. The primary difference was Yukon Energy had assumed a 2% escalation rate, but the final contract had a 4% escalation rate. The below compares the updated forecasts to the Application. The forecast for 2027 has also been updated to reflect the base 2026/27 contract price but has otherwise kept forecast assumptions for 2027 the same as the Application.

(\$000's)	2025	2026	2027
Updated Forecast	\$ 7,161	\$ 7,769	\$ 8,000
Application Forecast	\$ 6,987	\$ 7,095	\$ 7,233
Difference	\$ 174	\$ 674	\$ 767

¹ Application PDF page 76, lines 7-8.

REFERENCE: YEC 2025-2027 Application, PDF page 70

ISSUE: O&M Labour - Vacancy rate

QUOTE:

**Table 3.4:
Employee Complement History**

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
President & Corporate Services	3.10	3.10	3.34	3.29	3.10	3.10	4.10
Government Relations	1.00	2.00	1.00	-	-	-	-
Business Development	1.00	1.00	1.00	-	-	-	-
Communications & Customer Service	3.60	3.60	4.60	-	-	-	-
People & Culture	2.00	2.00	2.00	-	-	-	-
Partnerships & Business Services	-	-	-	15.05	15.25	16.50	18.00
Resource Planning, Environment, Health & Safety	10.60	11.13	11.10	11.98	12.60	14.85	14.85
Finance & Procurement	19.29	20.29	19.41	13.79	13.79	14.79	14.79
Operations	51.96	53.20	51.46	55.10	59.95	63.60	64.45
Engineering Services	20.50	23.50	19.75	24.25	24.25	27.00	28.25
Total FTE's	113.05	119.81	113.66	123.46	128.94	139.84	144.44
Vacancy	9.00	9.00	12.32	7.99	9.00	9.00	9.00
Total FTE's less Vacancy	104.05	110.81	101.34	115.47	119.94	130.84	135.44

Note:

1. The employee complement numbers are net of allocation to YDC.

2. In 2024, the positions under Government Relations, Business Development, Communications & Customer Service, People & Culture and IT were transferred to Partnerships & Business Services. Please see Table 3.4.1 for details.

QUESTION:

- a) Please provide the final actual 2024 employee complement and vacancy rate.
- b) Please provide the 5-year average vacancy rate based on actual information for 2020-2024.
- c) Please provide actual vacancy rates for 2025 on a monthly basis for January to July.
- d) Comparing the forecast total employee complement for 2025 of 128.94 with the same information for 2024, as provided in response to part (a), how many of the incremental positions have been filled as of the date of the response to this IR?

ANSWER:

While questions (a) through (c) ask for vacancy rate, Yukon Energy's response is based on vacancy factor, as vacancy factor was what was provided in the application, and Yukon

Energy believes this will provide more comparable information. Vacancy factor is measured in terms of FTEs, while vacancy rate is a different calculation and is measured in percentage terms.

(a)

The final actual 2024 employee complement was 123.71 FTEs, and the vacancy factor was 7.99 FTEs, as detailed below.

	2024 Actual
President & Corporate Services	3.29
Partnerships & Business Services	15.09
Resource Planning, Environment, Health & Safety	11.98
Finance & Procurement	14.00
Operations	55.09
Engineering Services	24.25
Total FTE's	<u>123.71</u>
Vacancy	<u>(7.99)</u>
Total FTE's less Vacancy	<u>115.71</u>

(b)

The 5-year average vacancy factor based on actual information for 2020-2024 was 9.91 FTEs, as detailed below.

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5-Year Average
Vacancy factor	(9.30)	(8.99)	(11.05)	(12.21)	(7.99)	(9.91)

(c)

Actual vacancy factors for 2025 monthly for January to June are detailed below. July was not available at the time of preparation of this response.

	January	February	March	April	May	June	Average
Vacancy factor	(5.40)	(5.37)	(4.32)	(2.29)	(5.14)	(7.55)	(5.01)

Please see YUB-YEC-1-37(c) for information on how the lower-than-average vacancy factor is impacting 2025 results.

(d)

Table 3.2A-1 on PDF page 118 of the application provides the list of additions planned for 2025. That table has been replicated below showing the status of those additions.

Title	Status
• Resource Planner	Filled
• Training Coordinator	Filled
• Maintenance Engineer – Mechanical	Filled
• Maintenance Engineer – Electrical	Interviewing
• Electrical Technologist	Filled
• Operation Technology (OT) Network and Automation Specialist	Filled
• Financial Analyst	Filled
• System Control Centre (SCC) Operator and Coach	Filled

In addition, due to increased thermal requirements and to reduce overtime, Yukon Energy is increasing the employee complement in 2025 by adding 1.25 Casual Plant Operator positions and assessing what other requirements may be needed for the upcoming winter.

Furthermore, on July 30, 2025, with the Yukon Water Board's issuance of the 20-year Whitehorse Rapids Generating Stations Water Use Licence, Yukon Energy is advancing the hiring of the planned 2026 FTE addition of the Permitting and Monitoring Coordinator to late summer 2025 to assist with the incremental workload to comply with the conditions of the new Licence. These additional conditions include requirements for more frequent environmental monitoring over a larger breadth of interests and geographic areas, ongoing collaboration with rightsholders and stakeholders, and more frequent and extensive reporting back to the Yukon Water Board on how conditions of the Licence are being fulfilled. Yukon Energy expects that further additional resources will be needed to deliver conditions of the 20-year Water Use Licence during the test periods of this rate application and will advise the Yukon Utilities Board of those additions as plans are advanced.

Please see YUB-YEC-1-37(c) for information on how the higher-than-expected thermal generation is impacting 2025 results.

REFERENCE: YEC 2025-2027 Application, PDF page 73

ISSUE: Labour – Capital to Maintenance allocation

QUOTE:

The 2024 approved revenue requirement forecasts included an allocation set at 17.9% capital and 82.1% maintenance. The 2024 actual results were 19.2% capital and 80.8% maintenance. For the 2025 test year the forecast allocation is 21.1% capital and 78.9% maintenance, for the 2026 test year the forecast allocation is 21.7% capital and 78.3% maintenance, and for the 2027 test year the forecast allocation is 21.7% capital and 78.3% maintenance. The ratio is based on Yukon Energy's best estimates for each employee's time to perform their job based on corporate goals and expectations and an overall increase in capital projects volumes.

QUESTION:

a) Please calculate the 5-year average capital to maintenance labour allocation based on actual information for 2020-2024.

b) Please explain any variance between the calculation provided in response to part (a) and YEC's proposed capital to maintenance allocations for 2025-2027 as provided in the above quote.

ANSWER:

(a)

The 5-year average capital to maintenance labour allocation based on actual information for 2020-2024 is 16.7% as detailed below.

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5-Year Average
Capitalized Labour	18.2%	16.7%	13.2%	17.2%	18.4%	16.7%

(b)

Note that the 2024 actual results quoted from PDF page 73 were preliminary actuals. The 2024 actual results were 18.4% as shown in part (a).

1 Also note that Yukon Energy is not 'proposing' a capital to maintenance allocation
2 percentage. This percentage is simply a resulting statistic that is calculated based on a
3 more detailed labour budgeting exercise. It is not a ratio that is determined and then
4 allocated to labour costs.

5
6 The process for budgeting labour at Yukon Energy starts with budget owners being
7 provided with details of prior year(s) actual allocations for each of their employees. A
8 reasonability check is done to factor in any assumptions that may change the findings
9 from one year to the next, such as if a major capital project was done in one year but not
10 another. Budget owners review and adjust the forecast year to the best of their knowledge
11 based on the expected plans in the forecast year. It is Yukon Energy's position that budget
12 owners have the best idea of workload of their staff for the upcoming year.

13
14 The hours of each employee are multiplied by each employee's expected loaded labour
15 rate, and then the total labour cost per employee is allocated to capital and maintenance
16 based on the budget owner input. All the employees are combined from all the budget
17 owners' inputs to come up with a companywide total cost. The capital to maintenance
18 allocation ratio is simply the result of these steps.

19
20 There is a significant variance between the calculation provided in response to part (a)
21 with a five-year average of 16.7% and Yukon Energy's capital to maintenance allocations
22 provided in the above quote of 21.1% capital for 2025 and 21.7% capital for 2026 and
23 2027. Factors that can affect the resulting capital to maintenance allocation include size,
24 scale and scope of each year's capital plan and staffing levels.

25
26 Historically, the amount of planned capital spending has been significantly less than the
27 planned capital spending in the GRA test years. The average capital spending from 2020–
28 2024 was slightly above \$40 million per year, whereas planned capital spending for 2025–
29 2027 is approximately \$116 million per year¹. With higher capital planned spending, it is
30 reasonable for a higher capital to maintenance allocation.

31
32 In preparation for increased capital spending, Yukon Energy has focused many of its
33 recent FTE additions in Engineering Services as this department performs much of the
34 capital labour through project management. The Engineering Services employee

¹ Calculated as the forecast Total Expenditures of 2025, 2026 and 2027 from Table 5.1 on PDF Page 206 of the application.

1 complement is increasing from 15.63 FTEs in 2020 to 28.25 FTEs in 2027. With a greater
2 number of employees hired to work on capital projects, it is reasonable for a higher capital
3 to maintenance allocation. While there is also a planned increase in Operations, these
4 additions should help reduce overtime costs and will also be partially allocated to capital
5 works.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 73-76

2
3 **ISSUE:** O&M – Production

4
5 **QUOTE:** “Approximately 77% of the forecast increase in 2025 over 2024
6 approved for production costs is due to higher labour cost [\$1.477
7 million increase in 2025 forecast over 2024 approved]. Approximately
8 74% of the forecast increase in 2027 over 2024 approved for production
9 costs is due to higher labour cost [\$2.413 million increase in 2027
10 forecast over 2024 approved].”

11 ...

12 “Public education – Yukon Energy continues to educate Yukoners on
13 ways they can reduce their electricity use, particularly in the winter
14 months. This has included regular posts on Yukon Energy’s Facebook
15 page and information on the Yukon Energy website. Yukon Energy has
16 also been promoting its Peak Smart program, as well as demand-
17 shifting practices such as using the delay start function on appliances
18 or using a block heater timer for vehicles, through social media,
19 traditional media and in-person events.”

20
21 **PREAMBLE:** It is not clear whether YEC’s reference to “higher labour cost” is
22 indicating that the higher labour costs are the result of higher wages, or
23 more than forecast labour hours, or some other factor leading to “higher
24 labour cost.”

25
26 **QUESTION:**

- 27
28 a) Please provide information addressing the lack of clarity with respect to YEC’s
29 assertion of “higher labour cost.”
30
31 b) Please confirm that the “Public education” program identified as Peak Smart is
32 outside of YEC’s DSM program as a specific O&M cost related to production rather
33 than the DSM program “Peak Smart” identified by YEC in its 2023-2024 GRA as a
34 capital project.¹

¹ YEC 2023-2024 GRA, Attachment 5.2A-2.1 Demand Side Management Program Design for YEC, PDF pages 279-284.

1 c) What is the total of approved and actual costs related to YEC's DSM Peak Smart
2 program that YEC has received as of December 31, 2024?

3
4 d) Regardless of whether YEC's assertion is that its Peak Smart program is outside
5 of the parameters of its DSM program, please explain why YEC's Public Education
6 cost as detailed in the quote above should be within the costs of the Production
7 function as opposed to, for example, the communication category of costs within
8 YEC's Administration function.

9
10 **ANSWER:**

11
12 **(a)**

13
14 Yukon Energy's reference to higher labour cost was meant to state a simple fact that the
15 2025 forecast production labour cost is greater than the 2024 approved production labour
16 cost. Yukon Energy was comparing the 2024 approved production labour cost of \$6.040
17 million to the 2025 forecast production labour cost of \$7.517 million, an increase of \$1.477
18 million.

19
20 The higher labour cost is due to both the result of higher wages and increased production
21 FTEs.

22
23 **(b) – (d)**

24
25 The reference to public education in Section 3.3.2 of the application is not a reference to
26 production costs. The reference to public education is provided as part of the discussion
27 related to the diesel rental business case, as diesel rentals are production costs. Yukon
28 Energy's discussion on diesel rental costs starts at line 9 on PDF page 74 of the
29 application and continues through to line 2 on PDF page 77 of the application. Lines 26
30 and 27 of the application on PDF page 74 states: "*In addition to the business case
31 assessment, Yukon Energy looked at various alternatives to reduce reliance on diesel
32 rentals for the 2025 to 2027 test years. These included....*" Public education is one of the
33 alternatives identified.

34
35 The public education paragraph starting on PDF page 75 of the application and continuing
36 on page 76 of the application consists of both general public education communications

- 1 and DSM promotions regarding the Peak Smart program. The general public education
- 2 communication is included in the communication category of costs within Yukon Energy's
- 3 Administration function.
- 4
- 5 All costs relating to Peak Smart are capitalized as part of Yukon Energy's DSM program.
- 6 The total costs to December 31, 2024 are \$1.009 million.

REFERENCE: YEC 2025-2027 Application, PDF pages 77-82

ISSUE: O&M – Brushing costs for Transmission and Distribution

QUOTE:

Table 3.6
Transmission and Distribution Costs
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 1,407	\$ 1,430	\$ 996	\$ 1,567	\$ 1,374	\$ 1,480	\$ 1,515
Brushing Cost	1,339	1,339	1,339	1,339	1,398	1,695	1,255
Other Non-Labour	722	498	641	834	643	656	669
Total T&D	\$ 3,468	\$ 3,267	\$ 2,976	\$ 3,740	\$ 3,415	\$ 3,831	\$ 3,438

Table 3.6.1
Brushing Costs
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Transmission Brushing	\$ 1,305	\$ 1,131	\$ 1,305	\$ 1,305	\$ 1,208	\$ 1,502	\$ 1,056
Distribution Brushing	34	208	34	280	190	193	199
% Transmission	97%	85%	97%	82%	86%	89%	84%
% Distribution	3%	15%	3%	18%	14%	11%	16%
Total Brushing Expense	\$ 1,339	\$ 1,339	\$ 1,339	\$ 1,585	\$ 1,398	\$ 1,695	\$ 1,255

Table 3.7.1
Transmission Costs
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 656	\$ 666	\$ 343	\$ 637	\$ 565	\$ 639	\$ 648
Brushing Cost	1,305	1,131	1,305	1,305	1,208	1,502	1,056
Other Non-Labour	480	279	283	223	407	414	425
Total Transmission	\$ 2,441	\$ 2,077	\$ 1,931	\$ 2,165	\$ 2,180	\$ 2,555	\$ 2,128

Table 3.7.2
Distribution Costs
(\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 751	\$ 764	\$ 653	\$ 930	\$ 808	\$ 841	\$ 867
Brushing Cost	34	208	34	34	190	193	199
Other Non-Labour	242	219	358	611	236	242	244
Total Distribution	\$ 1,027	\$ 1,190	\$ 1,045	\$ 1,575	\$ 1,235	\$ 1,276	\$ 1,310

QUESTION:

- a) Please confirm the combined Transmission and Distribution brushing costs for Preliminary Actual 2024 are the amount of \$1.339 million as shown on Table 3.6, notwithstanding that the equivalent combined Transmission and Distribution brushing costs as shown on Table 3.6.1 for Preliminary Actual 2024 indicates an amount \$1.585 million.

ANSWER:

(a)

Confirmed. There was a formula error in Table 3.7.2 Distribution Costs in that the Brushing Cost for Preliminary Actual 2024 was linked to the 2023 Actual Distribution Brushing cell rather than the Preliminary Actual 2024 cell. The corrected table is provided below. The changes are to Brushing Cost and Other Non-Labour in the Preliminary Actual 2024 column.

Table 3.7.2
Distribution Costs
(\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 751	\$ 764	\$ 653	\$ 930	\$ 808	\$ 841	\$ 867
Brushing Cost	34	208	34	280	190	193	199
Other Non-Labour	242	219	358	365	236	242	244
Total Distribution	\$ 1,027	\$ 1,190	\$ 1,045	\$ 1,575	\$ 1,235	\$ 1,276	\$ 1,310

1 A change in Table 3.7.2 has an impact on the Preliminary Actual 2024 column in Table
 2 3.6. The corrected table is provided below.

3

Table 3.6
Transmission and Distribution Costs
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 1,407	\$ 1,430	\$ 996	\$ 1,567	\$ 1,374	\$ 1,480	\$ 1,515
Brushing Cost	1,339	1,339	1,339	1,585	1,398	1,695	1,255
Other Non-Labour	722	498	641	588	643	656	669
Total T&D	<u>\$ 3,468</u>	<u>\$ 3,267</u>	<u>\$ 2,976</u>	<u>\$ 3,740</u>	<u>\$ 3,415</u>	<u>\$ 3,831</u>	<u>\$ 3,438</u>

4

5

6 The formula error does not impact other numbers in the application as the change in
 7 Brushing Cost is offset by the change in Other Non-Labour.

1 **REFERENCE: YEC 2025-2027 Application, PDF pages 82-83**

2
3 **ISSUE: O&M – General Operating and Maintenance**

4
5 **QUOTE:**

6
7 Maintenance of Company Owned Properties is expected to remain relatively stable from 2023 approved,
8 increasing on an average annual compound basis by approximately 1.7% through 2027. Actual costs in
9 2023 were exceptionally high for several reasons, including major staff housing maintenance costs and
10 significant Whitehorse office building plumbing repairs.

11
12 **QUESTION:**

- 13
14 a) Please identify the activities being performed in relation to the maintenance of
15 Company Owned Properties.
16
17 b) Please provide further details explaining the “major staff housing maintenance
18 costs” attributed to the increase for 2023-2024 actual costs compared to approved
19 costs.
20
21 c) Why are maintenance costs forecast to decrease for the 2025-2027 test period as
22 compared to actual 2023-2024 results?
23
24 d) With respect to SCADA Communication costs, please explain the lower 2023-2024
25 actual costs compared to 2023-2024 approved costs.
26
27 e) What justification can YEC provide for the 2025-2027 forecasts SCADA
28 Communication costs given the significantly lower actual 2023-2024 costs as
29 compared to 2023-2024 approved costs?

30 **ANSWER:**

31 **(a)**

32 Company Owned Properties include:

- Staff housing in the communities of Aishihik, Dawson, Faro and Mayo;
- Fish ladder building;
- Fish hatchery building;
- Offices and shops in Mayo, Faro and Dawson;
- Kulan warehouse;
- Whitehorse offices and buildings located at the Whitehorse Rapids Generating Station; and
- Additional T&D/warehouse rental land/buildings at Kulan.

Maintenance of Company Owned Property activities include general maintenance, elevator maintenance, janitorial, snow removal, fire protection, heating fuel, pest control, plumbing, security, carpentry, landscaping, sewer, water, garbage, compost and recycling.

(b)

The “major staff housing maintenance costs” in 2023 included:

- Heating fuel at Aishihik staff house where a combination of high levels of activity at Aishihik and the use of oil boilers rather than the electric heating system increased costs;
- Plumbing repairs at Aishihik staff house;
- Deck rebuild at Dawson staff house; and
- Plumbing repairs at Mayo staff house;

Maintenance of Company Owned Property costs in 2024 were greater than approved for various reasons, including:

- Dawson office boiler issues;
- Unusually high snow removal requirements;
- Roofing repairs at Mayo staff house.

(c)

Maintenance of Company Owned Property costs is forecast to decrease for the 2025-2027 test period as compared to 2023-2024 actual results because the major staff housing costs that occurred are not expected to reoccur. In addition, the additional T&D/warehouse

1 rental of land and buildings at Kulan was expensed as an operating lease in 2023 but the
2 renewed lease meets the definition of an asset and has been capitalized as a right-of-use
3 asset, resulting in the lease costs being included as depreciation expense rather than
4 under O&M expenses going forward.

5
6 **(d) and (e)**

7
8 Yukon Energy has invested in communications assets such as fiber thereby reducing
9 payments to third parties such as Northwestel and other satellite services. The 2025-2027
10 forecasts are consistent with 2024 actual results.

REFERENCE: YEC 2025-2027 Application, PDF pages 83-88

ISSUE: O&M – Administration

QUOTE:

**Table 3.9:
Administration
(\$000)**

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Labour	\$ 7,634	\$ 8,311	\$ 7,879	\$ 8,397	\$ 8,740	\$ 9,590	\$ 10,240
Resource Planning	108	108	71	60	59	60	62
Communications	175	175	170	170	221	225	230
Customer Accounting	423	356	337	287	332	338	345
Environmental Mgmt	361	361	667	899	953	972	991
General	852	834	898	1,031	945	964	983
Information Systems	1,491	1,441	1,369	1,495	1,715	1,750	1,785
Fish Hatchery	222	222	241	267	270	275	281
Safety	207	207	209	227	235	239	244
Training	150	150	120	112	168	171	175
Recruitment	439	457	486	405	514	512	573
Board of Directors	419	311	440	410	372	380	387
Union	121	91	74	91	96	110	61
Regulatory Affairs	8	11	14	2	4	4	4
Material Management	23	23	36	44	27	28	28
Contracting	58	18	42	55	39	40	40
Professional Development	15	15	6	0	15	15	16
Capital Projects Studies	0	0	0	0	1,000	1,000	1,000
Total Administration	\$ 12,705	\$ 13,092	\$ 13,060	\$ 13,951	\$ 15,705	\$ 16,674	\$ 17,446

QUESTION:

- a) For the following cost categories, please provide additional detail explaining why actual 2023-2024 costs are lower than the costs approved for the same period: Resource Planning, Customer Accounting, Training and Professional Development.

1 b) Respecting the statement “Administration expenses are forecast to be lower in
2 2027 from 2024 approved in...” noted on PDF page 86 at lines 11-15, please
3 provide further detail why this is the case for the following cost categories:
4 Resource Planning, Customer Accounting, Union and Regulatory Affairs.
5

6 c) With respect to Board of Directors costs as noted on PDF page 86 at lines 7-10,
7 please explain why the statement that “Board spending in a particular year is
8 dependent on strategic issues at the time” appears to imply that strategy is a fluid
9 activity rather than something that is systematically planned and executed such
10 that costs are predictable. As part of this response, for 2023-2024 actual costs and
11 2025-2027 forecast costs, please provide an allocation of Board of Directors
12 expenses for: 1) routine activities such as monthly meetings; and 2) expenses
13 related to activities such as “spending ... on strategic issues at the time.”
14

15 **ANSWER:**

16
17 **(a)**
18

19 Resource Planning actual costs were lower in 2023 and 2024 than approved for the same
20 period as Yukon Energy was able to rely more on staff rather than consultants. More
21 specifically, the recently created Resource Planning Engineer Specialist has taken on
22 additional responsibilities including:
23

- 24 • Subject matter expert in hydro optimization software and develops inflow
25 forecasts using predictive mathematical models;
26
- 27 • Recommends generation dispatch to minimize cost of generation, while meeting
28 regulatory, environmental and social requirements;
29
- 30 • Recommends short-term generation plans to allow for system maintenance while
31 reducing generation costs and maximizing system stability; and
32
- 33 • Subject matter expert in resource planning mathematical models to conduct
34 load forecasting and resource planning portfolio analysis.
35

36 Customer Accounting actual costs were lower in 2023 than approved for the same period
37 because the 2023 approved amount assumed a large cost to implement the new customer

1 billing system, which did not occur. Costs were lower in 2024 than approved for the same
2 period because of lower-than-expected costs of the new customer billing system, less
3 travel performed than expected by the supervisor and a vacancy of the meter reading
4 position resulted in less travel costs.

5 Lower actual training costs in 2023 and 2024 as compared to approved for the same
6 period can be attributed to several factors:

- 7
- 8 • In 2023, due to turnover within both the People & Culture (P&C) team and the
9 Senior Management Team, the focus on training shifted. As a result, some key
10 forecasted initiatives, such as the Senior Management Development Plans and
11 Systems Thinking training, were deferred due to resource constraints and
12 organizational change.
- 13
- 14 • In 2024, a significant portion of the budget was allocated to Operations; however,
15 work demands, and unforeseen emergencies prevented the completion of several
16 planned training activities. Meanwhile, P&C focused on modernizing training
17 delivery by shifting efforts toward securing and implementing a Learning
18 Management System, which officially launched in 2025.
- 19
- 20 • Additionally, in both years, apprenticeship training costs for the company's
21 apprentice were covered through the Yukon Government's apprenticeship
22 program, further reducing overall spending against the internal training budget.
- 23

24 The Professional Development costs are an allocation as required by Yukon Energy's
25 contract with its President & CEO. Due to lack of available time and cost pressures in
26 other areas, the President & CEO forfeited the professional development costs resulting
27 in actual costs being lower in 2023 and 2024 than approved for the same period.

28
29 **(b)**

30
31 Resource planning expenses are forecast to be lower in 2027 compared to 2024 Approved
32 costs as Yukon Energy expects to continue to perform the tasks identified in part (a)
33 internally rather than outsourcing to an external consultant.

34
35 Customer accounting expenses are forecast to be lower in 2027 compared to 2024
36 Approved costs as Yukon Energy has locked in a services agreement for the new billing
37 system that is less than previously estimated.

1 Union costs are cyclical and are highly dependent on when collective bargaining occurs.
2 Union expenses are forecast to be lower in 2027 compared to 2024 Approved costs as
3 Yukon Energy does not expect to incur significant collective bargaining costs in 2027.
4 Yukon Energy expects to complete a three-year collective bargaining agreement for the
5 period January 1, 2026, through December 31, 2028, in 2026.

6
7 Regulatory Affairs expenses are forecast to be lower in 2027 compared to 2024 Approved
8 costs as Yukon Energy has shifted to performing these duties internally rather than
9 outsourcing to an external consultant.

10
11 **(c)**

12
13 Yukon Energy sets out strategic priorities to drive the development of detailed operational
14 plans to ensure continuous progress and achievement of goals through creation of a
15 Strategic Plan on a five-year reoccurring basis. Each year, Yukon Energy reviews the
16 current status and sets goals and objectives for the upcoming year. As a result, Board
17 spending in a particular year is dependent on strategic issues at the time.

18
19 An allocation of Board of Directors expenses for: 1) routine activities such as monthly
20 meetings; and 2) expenses related to activities such as “spending ... on strategic issues
21 at the time” is detailed below.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-43

		(\$ thousands)				
		2023	2024	2025	2026	2027
		Actual	Actual	Forecast	Forecast	Forecast
Routine activities (meetings)						
Honoraria	\$	155	\$ 122	\$ 130	\$ 134	\$ 136
Meeting Travel/Meals/Rentals	\$	40	\$ 37	\$ 42	\$ 43	\$ 44
Other	\$	16	\$ 10	\$ 9	\$ 9	\$ 10
Total Routine activities	\$	211	\$ 170	\$ 181	\$ 186	\$ 190
Strategic activities						
Strategic Planning Consulting	\$	-	\$ 59	\$ 25	\$ 26	\$ 26
Strategic Plan Communications	\$	-	\$ 15	\$ 15	\$ 15	\$ 16
Board Training	\$	4	\$ -	\$ -	\$ -	\$ -
Consultant for Board Education	\$	4	\$ -	\$ 7	\$ 7	\$ 7
CEO Recruitment	\$	15	\$ -	\$ -	\$ -	\$ -
CEO Evaluation	\$	16	\$ 32	\$ 30	\$ 31	\$ 31
Director Evaluation	\$	18	\$ -	\$ 35	\$ 36	\$ 36
Legal	\$	122	\$ 85	\$ 30	\$ 31	\$ 31
Yukon University Research Grant	\$	50	\$ 50	\$ 50	\$ 50	\$ 50
Total Non-routine activities	\$	229	\$ 240	\$ 192	\$ 194	\$ 197
1 Total Board of Directors	\$	440	\$ 410	\$ 372	\$ 380	\$ 387

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 88

2
3 **ISSUE:** Criteria for Capitalization and other policies and procedures

4
5 **QUOTE:** Yukon Energy performed a comprehensive review of its capitalization
6 policies and has developed a new policy based on extensive research
7 of International Financial Reporting Standards (IFRS) and industry
8 guidance. Effective January 1, 2025, Yukon Energy has implemented
9 the policy FX-001 Criteria for Capitalization. A copy of this policy has
10 been provided in Appendix 5.3. In summary, this policy complies with
11 IFRS standards and requires expensing of costs that do not meet the
12 capitalization criteria. As a result, the category of Feasibility Studies will
13 cease to exist in the future as no new projects will be capitalized as
14 costs will no longer meet the capitalization criteria.

15
16 **QUESTION:**

17
18 a) Please identify by name and year of capitalization, all projects that are "... included
19 in this GRA for completion of studies already included as part of previous GRA..."

20
21 **ANSWER:**

22
23 **(a)**

24
25 Please note that the referenced quote is at PDF page 87.

26
27 Feasibility studies that continue to be included in this GRA for completion of studies
28 already included as part of previous GRAs until those projects are completed and fully
29 amortized are detailed below. All are included in Table 5.4 on PDF page 217 of the
30 application under Deferred Costs / Other Projects with <\$400k Spending. All are expected
31 to be completed and capitalized by the end of 2025.

- 32
33
 - AGS Fish Passage Study;
 - 34 • Aishihik Dam Breach Study;
 - 35 • Business Continuity Plan Development;
 - 36 • Critical Power Transformers and Reactors Study;
 - 37 • Customer Bill Structure;

- 1 • Dam Safety Program High Risk Study;
- 2 • Grid Modernization Study;
- 3 • Process Refinement Study;
- 4 • Project Management Software Study;
- 5 • Renewable Diesel Pilot;
- 6 • SF6 Dead Tank Breaker Study;
- 7 • Single Device Isolation Certification Program Development;
- 8 • System Fire Protection Assessment;
- 9 • System Wide Arch Flash Study;
- 10 • System Wide Stability Study;
- 11 • T&D Load Planning Study;
- 12 • WG0 Summer High Temp Study; and
- 13 • WH Slope Stability Assessment.

REFERENCE: YEC 2025-2027 Application, PDF pages 86-88

ISSUE: O&M Administration – Capital Project Studies (Feasibility Studies proposed to be expensed)

QUOTE: The change in the accounting treatment does not change the need for Yukon Energy to perform these studies. Based on industry guidance, Yukon Energy created a Capital Projects Studies budget to fund projects in the early stages and do not meet the capitalization criteria....

...

Yukon Energy is proposing a revenue requirement cost of \$1.000 million for each test year. This treatment will be beneficial to ratepayers as it is less than historic feasibility study spending and eliminates AFUDC on these projects. Projects that Yukon Energy is considering under this category include the following:

- Grid modernization strategy research, studies and pilots;
- Dawson diesel plant lifecycle study;
- Wareham spillway concrete assessment;
- Aishihik elevator moisture reduction assessment;
- ERP replacement research;
- WDO units voltage mis-regulation study;
- Development or requirements for a drafting drawing management system;
- Mayo diesel transformer foundation study;
- Marwell flood prevention design;
- Southern Lakes groundwater study;
- Phone system replacement study
- Dam safety audit;
- MCC inspection, condition assessment renewal option analysis;
- T&D emergency parts and stocking study;
- Communications data/OT/SCADA/IT link strategy and plan;
- WDO P126 Whitehorse diesel plant renewal study;
- Turbine welding standards;
- Thermal and permitting studies;
- Pressure vessel certification program;
- S251 StatCom retuning study;
- Aishihik fiber link install and connect study;
- Hazardous building materials assessment;
- PLT energized services development;
- T9 transformer critical spare business case study;
- Asset appraisals;
- Skagway shoreside power study.

1 **PREAMBLE:** It is not clear to the Board why certain of the potential “projects”
2 identified above would not or should not be encompassed within the
3 applied-for labour component of YEC’s operating or administrative
4 functions to which the project activity appears to relate.
5

6 **QUESTION:**
7

8 a) For example, please explain why the “phone system replacement study” would not
9 be conducted as part of the normal duties within a typical administrative function
10 and thus included in administration labour as opposed to YEC requesting to collect
11 additional O&M costs through what it purports is a stand-alone study.
12

13 b) Referring to the question posed in part (a), please respond in a similar manner for
14 the following:
15

- 16 i. ERP replacement research;
- 17 ii. Development or requirements for a drafting drawing management
- 18 system;
- 19 iii. T&D emergency parts and stocking study;
- 20 iv. Turbine welding standards.
21

22 c) For all other projects not identified in part (a) or part (b), what is the criteria that
23 YEC has relied on to determine that additional O&M costs are required as opposed
24 to being encompassed within the normal operating or administrative functions to
25 which the activity relates.
26

27 d) For all projects listed in the quote, please identify those “projects” that would have
28 a direct impact on the development and construction of a capital asset that meets
29 YEC’s capitalization criteria.
30

31 e) From all projects listed in the quote, please identify those “projects” that require
32 the use of personnel other than YEC staff.
33

34 f) From all projects listed in the quote, please identify those “projects” that have been
35 previously applied for (prior to 2025), otherwise confirm all “projects” in the list are
36 new to the current GRA.

1 **ANSWER:**

2
3 At the time of application preparation, Yukon Energy was engaged in a structured review
4 to determine the appropriate classification of projects—whether they should fall under
5 operative or administrative functions or be designated as capital project studies. The
6 project list provided was representative rather than exhaustive, intended to support
7 preliminary assessment without presupposing final categorization.

8
9 At the time of preparation of the response to this information request, Yukon Energy has
10 internally approved spending of \$974,000 for capital project study projects so far for 2025.
11 To June 30, 2025, actual capital project spending was \$53,000. Each of these studies
12 were viewed to result in a capital project, and therefore, it was categorized the way it was
13 and not attributed back to the department.

14
15 **(a)**

16
17 A phone system replacement study would not be conducted as part of the normal duties
18 within a typical administrative function as a phone system replacement would likely be
19 considered a capital asset. Based on section 3.0 of the Criteria for Capitalization policy
20 included on PDF page 433 of the application, a phone system implementation meets the
21 required criteria for capitalization as:

- 22
- 23 • The phone system would be used on a continuing basis for longer than one year;
 - 24
 - 25 • The phone system would be held for use in the generation, transmission or
 - 26 distribution of electricity directly or indirectly; and
 - 27
 - 28 • The cost of the phone system would be significant.
 - 29

30 Depending on the solution, a portion of the capital costs may be hardware, and a portion
31 may be intangible. The definition of intangible assets in section 5.0 of the Criteria for
32 Capitalization policy included on PDF page 436 of the application states “Examples of
33 intangible assets could include designs and implementation of new...systems.”

34
35 As a phone system replacement study does not meet the Identification Phase (Feasibility
36 Design Stage) criteria listed in the chart of additional guidance on determination of

1 capitalization on PDF page 433 of the application, the study cannot yet be considered
2 capital.

3
4 At this time, a phone system replacement study is being considered for 2026.

5
6 While construction of the phone system would be capital, ongoing monthly fees would not
7 be.

8
9 **(b)**

10
11 The following analyzes whether costs should or should not be encompassed within
12 operative or administrative functions as opposed to being classified as a capital project
13 study for the requested projects.

- 14
15 i. **ERP Replacement Research** would not be conducted as part of the normal duties
16 within a typical administrative function as an ERP system replacement would likely
17 be considered a capital asset. Based on section 3.0 of the Criteria for Capitalization
18 policy included on PDF page 433 of the application, an ERP system
19 implementation meets the required criteria for capitalization as:

- 20
21 ○ The ERP system would be used on a continuing basis for longer than one
22 year;
23
24 ○ The ERP system would be held for use in the generation, transmission or
25 distribution of electricity directly or indirectly; and
26
27 ○ The cost of the ERP system would be significant.

28
29 The definition of intangible assets in section 5.0 of the Criteria for Capitalization
30 policy included on PDF page 436 of the application states “Examples of intangible
31 assets could include designs and implementation of new...systems.” The existing
32 ERP system that will be replaced is currently a fully amortized intangible asset.

33
34 As the ERP replacement research does not meet the Identification Phase
35 (Feasibility Design Stage) criteria listed in the chart of additional guidance on
36 determination of capitalization on PDF page 433 of the application, these costs
37 cannot yet be considered capital.

1 The ERP replacement research has planned spending of \$50,000 in 2025.

2
3 ii. **Development or requirements for a drafting drawing management system**
4 would not be conducted as part of the normal duties within a typical administrative
5 function as drafting drawing management system replacement would likely be
6 considered a capital asset. Based on section 3.0 of the Criteria for Capitalization
7 policy included on PDF page 433 of the application, a drafting drawing
8 management system implementation meets the required criteria for capitalization
9 as:

- 10
11 ○ The drafting drawing management system would be used on a continuing
12 basis for longer than one year;
13
14 ○ The drafting drawing management system would be held for use in the
15 generation, transmission or distribution of electricity directly or indirectly;
16 and
17
18 ○ The cost of the drafting drawing management system would be significant.

19
20 The definition of intangible assets in section 5.0 of the Criteria for Capitalization
21 policy included on PDF page 436 of the application states “Examples of intangible
22 assets could include designs and implementation of new...systems.”
23

24 As the drafting drawing management system does not meet the Identification
25 Phase (Feasibility Design Stage) criteria listed in the chart of additional guidance
26 on determination of capitalization on PDF page 433 of the application, these costs
27 cannot yet be considered capital.
28

29 The drafting drawing management system has planned spending of \$50,000 in
30 2025.

31
32 iii. **A T&D emergency parts and stocking study** would not be conducted as part of
33 the normal duties within a typical administrative function as T&D emergency parts
34 would likely be considered a capital asset. Based on section 8.0 of the Criteria for
35 Capitalization policy included on PDF page 433 of the application, Emergency
36 parts meets the required criteria for capitalization as Critical Spares:

- The item is unique to the asset it supports (substitutes are not available and/or cannot be readily fabricated);
- The absence of this item would cause a significant loss of asset service availability or have a significant negative impact on safety, environment or regulatory requirements;
- The item has a long lead time for procurement; and
- There is an expectation of use of the item for more than one period.

As the T&D emergency parts and stocking study does not meet the Identification Phase (Feasibility Design Stage) criteria listed in the chart of additional guidance on determination of capitalization on PDF page 433 of the application, these costs cannot yet be considered capital.

iv. **Development turbine welding standards** would not be conducted as part of the normal duties within a typical administrative function as turbine welding standards would likely be considered a capital asset. Based on section 3.0 of the Criteria for Capitalization policy included on PDF page 433 of the application, development of turbine welding standards meets the required criteria for capitalization as:

- The turbine welding standards would be used on a continuing basis for longer than one year;
- The turbine welding standards would be held for use in the generation, transmission or distribution of electricity directly or indirectly; and
- The cost of the turbine welding standards would be significant.

The definition of intangible assets in section 5.0 of the Criteria for Capitalization policy included on PDF page 436 of the application states “Examples of intangible assets could include designs and implementation of new processes...”

As the development of turbine welding standards does not meet the Identification Phase (Feasibility Design Stage) criteria listed in the chart of additional guidance

1 on determination of capitalization on PDF page 433 of the application, these costs
2 cannot yet be considered capital.

3

4 The development of turbine welding standards has planned spending of \$50,000
5 in 2025.

6

7 **(c)**

8

9 For all other projects not listed in part (a) or (b), Yukon Energy uses the same approach.
10 The costs may lead to a capitalized asset, but they do not yet meet capitalization criteria
11 as described in the Criteria for Capitalization policy included in Appendix 5.3, starting on
12 PDF page 431 of the application.

13

14 **(d) to (f)**

15

16 The table below summarizes those “projects” that would have an impact on the
17 development and construction of a capital asset that meets YEC’s capitalization criteria,
18 those “projects” that require the use of personnel other than YEC staff and those “projects”
19 that have been previously applied for (prior to 2025).

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-45

Project	Would have impact on development and construction of capital asset that meets criteria	Require external support	Project previously applied for or new to this GRA	Notes
Grid modernization study	Yes	Yes	New	
Wareham spillway concrete assessment	Yes	Yes	Previous GRA	1
ERP replacement research	Yes	Yes	Previous GRA	2
Development of drafting drawing management system	Yes	Yes	New	
Southern Lakes groundwater study	Yes	Yes	New	
Dam safety audit	Yes	Yes	New	
T&D emergency parts	Yes	Yes	New	
WDO P126 Whitehorse diesel plant study	Yes	Yes	Previous GRA	3
Thermal and permitting studies	Yes	Yes	New	
S251 Statcom retuning study	Yes	Yes	New	
Hazardous building materials assessment	Yes	Yes	New	
T9 transformer critical spare study	Yes	Yes	Previous GRA	4
Dawson diesel plant lifecycle study	Yes	Yes	New	
Aishihik elevator moisture reduction assessment	Yes	Yes	Previous GRA	5
WDO units voltage mis-regulation study	Yes	Yes	New	
Mayo diesel transformer foundation study	Yes	Yes	New	
Marwell flood prevention design	Yes	Yes	New	
Phone system replacement study	Yes	Yes	New	
MCC inspection, condition assessment renewal study	Yes	Yes	New	
Communications strategy and plan	Yes	Yes	New	
Turbine welding standards	Yes	Yes	New	
Pressure vessel certification program	Yes	Yes	New	
Aishihik fiber link study	Yes	Yes	New	
PLT energized services development	Yes	Yes	New	
Asset appraisals	No	Yes	New	
1 Skagway shoreside power study	Yes	Yes	Previous GRA	6

Notes:

1) Repairs for the Wareham Spillway Concrete were applied for in the 2023/24 GRA and approved as a capital asset.

2) ERP Replacement was identified in the 2023/24 GRA as an intangible asset but remained in WIP at the end of 2024.

3) P126 Building Renovation was identified in the 2023/24 GRA as a feasibility study capitalized in 2022.

4) A T9 Transformer assessment was completed in 2018/19.

5) A smaller study on the Aishihik elevator was included in the 2021 GRA and approved as a feasibility study capitalized in 2020.

- 1 6) Skagway shoreside power study was identified in the 2023/24 GRA as a feasibility
- 2 study but remained in WIP at the end of 2024.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 88;
2 Board Order 2024-05 Appendix A Errata, PDF page 82
3

4 **ISSUE:** Criteria for Capitalization and other policies and procedures
5

6 **QUOTE:** Board Order 2024-05 Appendix A Errata identified several policies or
7 procedures documents related to various aspects of YEC's
8 capitalization processes:

9 "• Finance Policy, FA-016 whose purpose was to "to define the
10 accounting policy for costs incurred in relation to planning activities."

11 • Finance Account Practice, FX-005 whose purpose was to "provide
12 guidelines for capitalization and amortization of study costs."

13 • Finance Account Practice, FX-008 whose purpose was to "provide
14 guidelines for intangible assets..."

15 • Finance Accounting Practice, FX-Appendix, whose purpose was to
16 "provide detailed definitions for various Property, Plant and Equipment
17 (PP&E) terminologies."

18 • Finance Accounting Practice, FX-004 on the topic of AFUDC.³
19 (footnotes omitted)
20

21 **QUESTION:**
22

23 a) Please clarify if policy FX-001 Criteria for Capitalization is a newly created, or an
24 updated version of any existing documents identified in the quote. If so, what
25 existing document does FX-001 Criteria for Capitalization replace?
26

27 b) Please identify if, as a result to the proposed creation or update of policy FX-001
28 Criteria for Capitalization, any of the documents identified in the quote required
29 modification, or if any additional documents have been required to be drafted.
30

31 c) If modifications (or the creation of documents) were required to any document
32 identified in part (b), in order to align with the FX-001 Criteria for Capitalization
33 document, please provide an updated document in both blackline and clean
34 version formats.

³ Board Order 2024-05 Appendix A Errata, PDF page 82.

1 d) Please confirm that all documents not identified in part (c) remain relevant from an
2 operational perspective.

3
4 **ANSWER:**

5
6 **(a)**

7
8 FX-001 Criteria for Capitalization is a newly created accounting practice guideline to assist
9 users in determining whether expenditures should be capitalized or expensed. It
10 consolidates and replaces other policies and practices into one document. It replaces
11 Finance Policy, FA-016, FX-002 Capital Leases, FX-002 Overhauls, FX-005 Feasibility
12 Studies, FX-007 Critical Spares, FX-008 Intangible Assets and FA-016 Planning Cost
13 Accounting Policy.

14
15 **(b) to (d)**

16
17 The documents identified in the quote have been replaced by FX-001 Criteria for
18 Capitalization except for Finance Accounting Practice, FX-Appendix, whose purpose was
19 to “provide detailed definitions for various Property, Plant and Equipment (PP&E)
20 terminologies” and Finance Accounting Practice, FX-004 on the topic of AFUDC. No
21 changes were made to the two documents that were not replaced. These documents
22 remain relevant.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 89-91

2
3 **ISSUE:** O&M - Insurance Costs

4
5 **PREAMBLE:** YEC completed a public tender process for insurance broker services
6 to confirm that ratepayers are receiving the best value for money from
7 this annual expense.

8 **QUESTION:**

9
10 a) How many responses were received with respect to YEC's public tender process
11 for insurance broker services?

12
13 b) How were the criteria to determine "best value for money" from the annual
14 insurance expense applied in the case of the new broker Marsh? For example, if
15 there was a cost savings component, what were the savings in comparison to the
16 lowest, next lowest and highest cost insurance quotes compared to the value
17 received with Marsh?

18
19 c) Please identify all property insurance claims of YEC in the last 10 years and the
20 related deductible amount paid by YEC. Would these claims have had any bearing
21 on the cost or availability of YEC's property insurance coverage including the
22 deductible portion?

23
24 d) Has the deductible portion of the property insurance policy changed from the
25 amount last identified by YEC of \$1 million?¹ If so, please provide further details.

26
27 **ANSWER:**

28
29 **(a)**

30
31 Yukon Energy received three responses with respect to its public tender process for
32 insurance broker services.

¹ YEC 2023-2024 GRA, combined all party responses, YUB-YEC-1-53(c), PDF page 425: "In 2021, YEC increased the deductible on our property policy from \$500k to \$1M which 20 resulted in premium savings of \$175k."

(b)

The procurement process for insurance broker services followed normal Yukon Energy evaluation practices. Proponents were evaluated on corporate experience, work approach/methodology, experience of proposed team, references, and pricing. There was no cost savings component in the decision to award the contract to Marsh. The decision to award the contract to Marsh was based on Marsh scoring better in the technical categories of corporate experience, work approach/methodology and experience of the proposed team. The overall ranking, which included both the technical and pricing component, resulted in Marsh receiving the higher overall score.

(c)

The following table includes all completed property insurance claims in the last 10 years:

Date of Loss	Description	Total Claim	Deductible
11-Apr-20	WG2 unit failure	514,955	100,000
28-May-20	WH1&2 penstock deformation	6,748,286	100,000
18-Oct-21	Lewes River boat lock damage	5,520,488	1,000,000

This does not include two ongoing claims that occurred in the 2024-2025 policy year (Aishihik unit #1 generator and Mayo penstock). The net claim amounts paid by insurers (total claim less deductible) have the greatest impact on the cost and availability of insurance compared to other factors.

(d)

As part of the June 1, 2025, property insurance renewal, the deductible was increased to \$5.0 million.

The 2024 property insurance premium was approximately \$2.1 million. In Yukon Energy's Application, several actions were listed to potentially reduce the cost of insurance in the future, including "Risk financing optimization analysis to determine the potential of retention changes to offset rate increases. Yukon Energy, in conjunction with its new

insurance broker, Marsh, is in the process of assessing the property insurance deductible.” (PDF page 90). During the property insurance renewal process in the second quarter of 2025, Yukon Energy through negotiations by Marsh with the insurance companies, concluded there were essentially two options for Yukon Energy to consider:

- i. Increase the deductible from \$1 million to \$3 million, with a premium cost of approximately \$4.3 million per year (premium increase of over 100%); or
- ii. Increase the deductible from \$1 million to \$5 million, with a premium cost of approximately \$2.3 million per year (premium increase of approximately 12%).

The Application forecast an overall rate increase of 25% on property policy² but this was made under the assumption that there was no increase in the deductible. The insurance companies did not offer an option to maintain the deductible at \$1 million.

Yukon Energy’s forecast property insurance cost included in the Application was based on the best information available at the time and is supported by actual results of the insurance negotiations. However, as Yukon Energy has agreed to a policy with a higher deductible than assumed in the Application, insurance expense for 2025 is now forecast to be less than submitted in the Application. Based on the same escalation rate as assumed in the Application, the 2026 and 2027 insurance expense is also now forecast to be less than submitted in the Application. The below compares the updated forecasts to the Application.

(\$000's)	2025	2026	2027
Updated Forecast	\$ 2,205	\$ 2,501	\$ 2,551
Application Forecast	\$ 2,487	\$ 2,820	\$ 2,877
Difference	\$ (282)	\$ (319)	\$ (326)

² Application PDF page 89, lines 10-11.

REFERENCE: YEC 2025-2027 Application, PDF pages 91-92

ISSUE: Annual amortization of Reserve for Injuries and Damages (RFID)

QUOTE:

As part of the 2021 GRA, the Board approved amortization of the 2020 negative balance over a 10-year period (\$0.205 million per year) and an annual appropriation of \$0.411 million per year to total annual appropriation of \$0.616 million. No changes were made during the 2023/24 GRA.

Table 3.11.1 below shows that the RFID balance owing from customers at the end of 2024 was \$5.086 million, reflecting higher recent costs.

**Table 3.11.1:
RFID Continuity Schedule
(\$000)**

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	-\$3,343	-\$3,281	-\$3,343	-\$3,282	-\$5,086	-\$4,577	-\$4,069
Annual Appropriation	616	616	616	616	1,063	1,063	1,063
Net Annual Costs	-554	-682	-555	-2,420	-554	-554	-554
Closing Balance	-\$3,281	-\$3,347	-\$3,282	-\$5,086	-\$4,577	-\$4,069	-\$3,560

Consistent with calculations in previous GRA's, Yukon Energy is proposing the opening RFID balance (of \$5.086 million at the end of 2024) be amortized over a period of ten years (or \$0.509 million per year).

The proposed total annual appropriation for the test years is \$1.063 million, calculated as the base appropriation of \$0.554 million plus \$0.509 million reflecting amortization of the opening balance.

QUESTION:

- a) Please confirm that the portion of the previous total annual appropriation of \$0.616 million pertaining to the amortization of the 2020 negative balance of \$2.050 million (or \$0.205 million per year for 10 years) has been replaced with an amortization of the 2024 negative balance of \$5.086 million (or \$0.509 million per year for 10 years) before taking into account, the annual base amortization of \$0.554 million per year.
- b) Please explain if the approach to "reset" the amortization of a previous year ending balance consistent with the approach YEC has taken with respect to all other of its deferral and reserve accounts? If so, please provide reasons for the differing approaches to amortizing YEC's deferral and reserve accounts.

1 **ANSWER:**

2
3 **(a)**

4
5 Confirmed.

6
7 **(b)**

8
9 The approach to “reset” the amortization of a previous year ending balance is consistent
10 with prior GRAs with respect to the RFID amortization and is consistent with all other
11 deferral and reserve accounts, including the annual appropriation for the Hearing Cost
12 Reserve Account included in this application.

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 92-93

2
3 **ISSUE:** Property Taxes

4
5 **QUOTE:** Property taxes are forecast to decrease \$0.006 million in 2025 from
6 2024 approved, increase by \$0.019 million in 2026 and increase by
7 \$0.016 million in 2027 due to rate increases and valuation updates.
8 Actual property taxes decreased in 2025 due to lower-than-expected
9 rate increases and valuation updates. Forecast property taxes in 2025
10 are based on invoiced cost for the period January 1, 2025 through June
11 30, 2025, increasing by 3% from July 1, 2025 through June 30, 2026,
12 increasing by 2% July 1, 2026 through June 30, 2027, and increasing
13 by 2% on July 1, 2027.
14

15 **QUESTION:**

16
17 a) Please provide reasons for the lower-than-expected valuation updates.

18
19 b) Please explain why lower-than-expected rate increases and valuation updates are
20 not anticipated over the 2025-2027 test years.
21

22 **ANSWER:**

23
24 **(a)**

25
26 The majority of the variance relates to the City of Dawson. In the 2023/24 GRA, Yukon
27 Energy expected taxes at all locations to increase moderately. However, the dollar amount
28 of 2024 property taxes for the City of Dawson remained consistent with 2023 invoices.
29 The 2024 invoice for the City of Dawson showed a slightly lower cost than 2023. The MIL
30 rate for non-residential was reduced from 1.94 percent to 1.92 percent.
31

32 **(b)**

33
34 Yukon Energy uses the best available information at the time of setting test year forecasts.

35
36 Yukon Energy has not stated that valuation updates are not anticipated. Valuation updates
37 are possible but not reasonably estimable.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 95; Tab 3 Schedules,
2 **Schedule 3.13 Depreciation and Amortization**

3
4 **ISSUE:** Depreciation Expense, Amortization of Contributions and Lewes River
5 Boat Lock Insurance proceeds

6
7 **QUOTE:**

3.4.2 Contributions

As a component of net depreciation costs, the revenue requirement includes substantial credits related to amortization of contributions (customer contributions and contributions from Yukon Development Corporation, Yukon government and Federal Government). This offset has changed from \$5.679 million in 2024 approved to \$5.933 million forecast in 2025, \$6.358 million forecast in 2026, and \$6.684 million forecast in 2027.

3.4.3 Amortization of Lewes River Boat Lock Insurance Gain

As identified in the 2023/24 GRA, Yukon Energy incurred damages and costs to the Lewes River Boat Lock due to the largest recorded flooding event along the Yukon River in 2021. Forecast costs in work-in-progress at the end of 2024 were \$15.514 million. However, this project has been put on hold. Costs relating to the project are summarized in this Application in Section 5.2.2. Further description of the project is shown in Appendix 5.1B.

Also included in the work-in-progress balance at the end of 2024 in the 2023/24 GRA was forecast contributions of \$4.520 million, representing the forecast insurance gain on the boat lock. Yukon Energy intended on keeping this amount in work-in-progress until the Boat Lock was repaired and then planned to request it be amortized on a similar basis to the new boat lock. However, as this project has been put on hold and has an unknown future, Yukon Energy is requesting the gain of \$4.520 million be amortized to revenue over the 3-year term of this application, being 2025, 2026 and 2027, or \$1.507 million per year. This treatment results in reducing the rate impacts of each test year. Accounting rules require recognition of the insurance proceeds immediately.

Table 3.13
Depreciation and Amortization
 (\$000)

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Fixed Asset Depreciation	\$ 14,244	\$ 15,350	\$ 16,005	\$ 15,719	\$ 20,658	\$ 24,529	\$ 27,658
Less: Contributions	(5,656)	(5,679)	(6,480)	(5,705)	(5,933)	(6,358)	(6,684)
Less: Lewes River Boat Lock insurance recoveries					(1,507)	(1,507)	(1,507)
Less: Amortization of fire insurance recoveries	(262)	(262)	(262)	(262)	(262)	(262)	(262)
Less: Disallowed Depreciation	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Plus: Amortization of deferred charges	4,536	5,345	3,690	5,436	7,006	7,488	6,893
Plus: Net Salvage Annual Appropriation					350	350	350
Total Depreciation & Amortization	\$ 12,811	\$ 14,703	\$ 12,902	\$ 15,137	\$ 20,261	\$ 24,190	\$ 26,398

QUESTION:

- a) Please provide an explanation for the variance in Fixed Asset Depreciation expense between: 2023 approved and actual; 2024 approved and 2025 forecast; 2025 and 2026 forecast; and 2026 and 2027 forecast, as noted in row 1 of Table 13 above.
- b) Please provide the same variance information as in part (a) for Amortization of Deferred Charges, as noted in row 5 of Table 13 above.
- c) Please provide a reference to where information for the calculation of the Amortization of Contribution expense (row 2 of Table 3.13 above) can be found within YEC's application or Tab attachments.
- d) Please confirm whether the contributions of \$4.520 million, representing the insurance "gain" on flooding related to the Lewes River Boat Lock project, remains a forecast, or if the funds have been received. If all anticipated funds have not been received, please describe when the funds are expected to be received. If all expected funds from the Lewes River Boat Lock claim have been received, please confirm that the amount received was \$4.520 million or explain why the amount received is different.
- e) YEC has recorded the proceeds of \$4.520 million from the insurance claim with respect to the Lewes River Boat Lock as a reduction to depreciation expense over three years rather than as a reduction to the CWIP balance for the project which YEC indicates is now on hold. Please prepare an analysis comparing the two

1 treatments (credit to depreciation expense versus credit to CWIP) and the impact
2 to ratepayers given that recording the \$4.520 million as a reduction to CWIP would
3 have the effect of lowering any AFUDC being calculated on the Lewes River Boat
4 Lock project CWIP balance.

5
6 f) Please provide reasons why the proceeds of \$4.520 million from the insurance
7 claim with respect to the Lewes River Boat Lock cannot be recognized in its entirety
8 as either a reduction to depreciation expense or a reduction to CWIP upon receipt
9 of the funds.

10
11 g) With respect to the Lewes River Boat Lock project, please explain why “this project
12 has been put on hold and has an unknown future.”

13
14 **ANSWER:**

15
16 **(a)**

17
18 Fixed Asset Depreciation:

- 19
20 • The variance between the 2023 actual and approved is primarily due to the \$1.3
21 million adjustment related to the prior years, posted in 2023. This was related to
22 Statcom equipment, which the Board, in its Order 2022-03 directed to amortize
23 over the VG mine life. In 2023, Yukon Energy noticed that the amortization was
24 not set up in accordance with the Board’s direction. Therefore, in 2023, the
25 adjustment was made to prior years to correct the amortization and was posted in
26 2023, impacting the 2023 depreciation expense.
- 27
28 • The increase of \$5.3 million in the 2025 forecast over 2024 mostly reflects:
- 29
30 ○ Capital additions in 2024: The 2023/24 GRA, 2024 forecast did not include
31 depreciation expense for the 2024 capital additions. The Board Order
32 2024-13, approving Yukon Energy’s 2023/24 GRA compliance Filing,
33 accepted this for the 2023/24 GRA Compliance purposes [i.e., the 2024
34 approved depreciation expense did not include depreciation for the 2024
35 capital additions]. The impact of the 2024 capital additions in the 2025
36 depreciation expense is approximately \$1.4 million.

1 ○ In paragraph 16 of its Order 2024-13, the Board highlighted the “apparent
2 lack of depreciation expense on current year forecast capital additions” and
3 in paragraph 20 further stated that “for forecast revenue requirement
4 purposes, a new asset is assumed to be capitalized at the mid-point of a
5 given test year and therefore provides for a half-year of depreciation
6 expense and a half-year of return on rate base. This practical application
7 of the mid-year convention serves to avoid any requirement for the utility to
8 estimate exact dates of asset capitalization as it impacts depreciation
9 expense and return calculations given the inherent assumption that
10 capitalization occurs at the mid-point of the year.” Accordingly, in the 2025-
11 27 GRA, Yukon Energy added depreciation expense for the 2025 capital
12 additions that would not have been included based on the approach
13 previously used by Yukon Energy. Approximately \$1.7 million depreciation
14 expense related to the 2025 capital additions was calculated based on a
15 mid-year approach as described by the Board. The detailed calculations
16 are provided in Schedule 3A-2025 of Tab 7.

17
18 ○ The Board in Order 2024-05 [2023/24 GRA decision], Appendix A,
19 paragraph 189 directed Yukon Energy to file a revised Schedule 3A “in
20 which it will insert a column indicating the depreciation rate being used, and
21 to include working formulae in the column of the schedule where the
22 forecast depreciation expense is being calculated, including the forecast
23 depreciation expense on current year additions.” In the 2023/24 GRA
24 Compliance Filing, Yukon Energy noted that it uses Microsoft Great Plains
25 to track its assets and calculate depreciation and amortization and system
26 depreciation estimate generates no depreciation and amortization expense
27 for the assets with zero net book value, i.e., fully amortized assets. Yukon
28 Energy further noted that to simplify the Board’s review process, in future
29 GRAs, the calculation of depreciation expenses for forecast years be based
30 on the approach that takes: 1) The asset cost by asset class for the prior
31 year times depreciation rate; plus, 2) Half of current year additions by asset
32 class times depreciation rate to get the total depreciation expense for the
33 test year. Yukon Energy also noted that this would also be consistent with
34 how AEY forecasts depreciation expenses in its GRAs [please see
35 Schedule 7.2 of AEY’s 2023/24 GRA]. This is also consistent with how the
36 depreciation rates are determined in the depreciation study [i.e., based on
37 a group of assets in the asset class, regardless of whether or not the asset

1 is fully depreciated]. Accordingly, Schedule 3A in Tab 7 provides details of
2 the depreciation expense calculations for each of the 2025, 2026 and 2027
3 test years as described above, including depreciation expense for the
4 current year additions as directed by the Board with working formulae
5 intact. The impact from the depreciation related to the assets with net book
6 value be the end of 2024 is approximately \$1.6 million.

- 7
- 8 • The increase of \$3.9 million in the 2026 forecast over the 2025 forecast reflects:
9
 - 10 ○ \$1.7 million for the 2025 capital additions. The 2025 depreciation expense
11 for the 2025 capital additions is calculated on a mid-year approach and only
12 half of the annual depreciation expense is included in the revenue
13 requirements for 2025; while the 2026 forecast includes the full year impact
14 of the 2025 capital additions.
 - 15
 - 16 ○ Capital additions in 2026 - approximately \$2.2 million depreciation expense
17 related to the 2026 capital additions calculated based on a mid-year
18 approach as provided in Schedule 3A-2026 of Tab 7.
 - 19
 - 20 • The increase of \$3.1 million in the 2027 forecast over the 2026 forecast reflects:
21
 - 22 ○ \$2.2 million for the 2026 capital additions. The 2026 depreciation expense
23 for the 2026 capital additions is calculated on a mid-year approach and only
24 half of the annual depreciation expense is included in the revenue
25 requirements for 2026; while the 2027 forecast includes the full year impact
26 of the 2026 capital additions.
 - 27
 - 28 ○ Capital additions in 2027 - approximately \$0.9 million depreciation expense
29 related to the 2027 capital additions calculated based on a mid-year
30 approach as provided in Schedule 3A-2027 of Tab 7.
 - 31

32 **(b)**

33

34 Amortization of Deferred Costs:

35

- 36 • The 2023 actual amortization expense was \$0.846 million lower compared to the
37 2023 approved, mostly due to the Southern Lakes Enhanced Storage (SLESP)

1 project. The Board in its Order 2024-05, para 310-311 stated that the \$8.784
2 million in project costs should have been capitalized into rate base in November of
3 2022 with amortization starting in November 2022 [with \$0.878 million amortization
4 also recorded in 2023]. However, at the time of the issuance of the Board Order,
5 the 2023 financial results were already closed. Therefore, the 2023 actuals did not
6 include the amortization for SLESP. The adjustment was made in 2024 to include
7 amortization for SLESP starting in November 2022, as directed by the Board, and
8 2025-27 GRA includes the net rate base for the project net of amortization
9 expenses starting from November 2022.

- 10
- 11 • The increase of \$1.6 million in the 2025 forecast over 2024 mostly reflects the
12 following:
13
 - 14 ○ Amortization related to the 2025 additions as illustrated in Schedule 3B –
15 2025:
16
 - 17 ▪ The amortization of the feasibility costs is increased by \$0.2 million
18 due to the added amortization for the 2025 additions.
19
 - 20 ▪ The amortization of the regulatory costs, including DSM, is
21 increased by \$0.06 million due to the added amortization for the
22 2025 additions.
23
 - 24 ▪ The amortization of the relicensing costs is increased by \$0.7
25 million due to the added amortization for the 2025 additions,
26 including Whitehorse relicensing, Mayo relicensing and Mayo Lake
27 Enhanced Storage projects.
28
 - 29 ▪ The amortization of the dam safety review costs is increased by
30 \$0.02 million due to the added amortization for the 2025 additions.
31
 - 32 ▪ The amortization of the intangibles is increased by \$0.2 million due
33 to the added amortization for the 2025 additions.
34
 - 35 ○ Amortization expense related to the 2024 additions: The 2023/24 GRA,
36 2024 forecast did not assume amortization expense for the 2024 additions.

- 1 ▪ The amortization of the feasibility costs is increased by \$0.4 million
2 due to the added amortization for the 2024 additions.
3
- 4 ▪ The amortization of the regulatory costs, including DSM, is
5 increased by \$0.1 million due to the added amortization for the 2024
6 additions.
7
- 8 ▪ The amortization of the relicensing costs is increased by \$0.02
9 million due to the added amortization for the 2024 additions.
10
- 11 • The increase of \$0.5 million in the 2026 forecast over the 2025 forecast reflects:
12
 - 13 ○ The amortization of the relicensing costs is increased by \$0.4 million due
14 to the added amortization for the Whitehorse and Mayo water use license
15 renewals [both projects are forecast to be closed in 2025, with only half of
16 the annual amortization in 2025 due to the mid-year approach; in 2026,
17 both projects have the whole annual amortization expenses].
18
 - 19 ○ The remaining variance is due to a reduction in feasibility study costs [-
20 \$0.09 million], a reduction in amortization of the dam safety review costs [-
21 \$0.006 million], an increase in amortization of the regulatory costs [\$0.07
22 million], and an increase in amortization of the intangibles [\$0.08 million].
23
- 24 • The reduction of \$0.6 million in the 2027 forecast from the 2026 forecast reflects:
25
 - 26 ○ There is no amortization related to the Vegetation Management deferral
27 account balance for 2027, as the deferred costs are fully amortized by the
28 end of 2026. This reduces the amortization expense by \$0.2 million.
29
 - 30 ○ The amortization of the feasibility study costs is reduced by \$0.6 million as
31 seven projects are fully amortized by the end of 2026.
32
 - 33 ○ The amortization of the relicensing costs is increased by \$0.2 million due
34 to the added amortization for the Aishihik 25-year water use license
35 renewal.

- 1 ○ The remaining variance is due to a reduction in amortization of the dam
2 safety review costs [-\$0.03 million], an increase in amortization of the
3 regulatory costs [\$0.07 million], an increase in amortization of the
4 intangibles [\$0.06 million] and a reduction in amortization of the DSM
5 contributions [-\$0.09 million] which increases the net amortization expense.
6

7 While working on the response to the questions, Yukon Energy noted that amortization
8 periods in Tab 7, Schedule 3B – 2025, Schedule 3B – 2026 and Schedule 3B – 2027, for
9 the Whitehorse Rapids Generating Station (WRGS) and Mayo Generating Station (MGS)
10 Water Use Licence Renewals were incorrect. The amortization for WRGS should be 20
11 years [as noted in section 5.2A-13 of the Application], not 25 years shown in the
12 schedules, while the amortization period for MGS should be 5 years [as noted in section
13 5.2A-3 of the Application], not 25 years shown in the schedules. These corrections
14 increase the amortization expenses for 2025 [\$0.637 million], 2026 [\$1.273 million] and
15 2027 [\$1.273 million] as shown in the table below [in \$000]. There will be offsetting
16 reductions in the return on rate base due to the reduction of the net rate base [net of
17 amortization]. Yukon Energy will reflect these corrections in the compliance filing.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-50

	Total Expenditures			NBV	Amortization Period	
	Dec 31	2025 Forecast	Dec 31	Dec 31		2025
	2024	Additions	Transfers /Retired	2024		Amortization Expenses
As filed						
Whitehorse Relicensing		10,608	10,608	-	25	212
Mayo Relicensing		7,295	7,295	-	25	146
Total						358
Corrected						
Whitehorse Relicensing		10,608	10,608	-	20	265
Mayo Relicensing		7,295	7,295	-	5	729
Total						995
					Change	637

	Total Expenditures			NBV	Amortization Period	
	Dec 31	2026 Forecast	Dec 31	Dec 31		2026
	2025	Additions	Transfers /Retired	2025		Amortization Expenses
As filed						
Whitehorse Relicensing	10,608		10,608	10,396	25	424
Mayo Relicensing	7,295		7,295	7,149	25	292
Total						716
Corrected						
Whitehorse Relicensing	10,608		10,608	10,343	20	530
Mayo Relicensing	7,295		7,295	6,565	5	1,459
Total						1,989
					Change	1,273

	Total Expenditures			NBV	Amortization Period	
	Dec 31	2027 Forecast	Dec 31	Dec 31		2027
	2026	Additions	Transfers /Retired	2026		Amortization Expenses
As filed						
Whitehorse Relicensing	10,608		10,608	9,971	25	424
Mayo Relicensing	7,295		7,295	6,857	25	292
Total						716
Corrected						
Whitehorse Relicensing	10,608		10,608	9,812	20	530
Mayo Relicensing	7,295		7,295	5,106	5	1,459
Total						1,989
					Change	1,273

1 (c)

2
3 The details of the amortization of the contributions for the deferred cost are provided in
4 Schedule 3B – 2025, Schedule 3B – 2026 and Schedule 3B – 2027.

5
6 Please see YUB-YEC-1-50 Attachment 1 for the details of the calculation of the
7 amortization expense of the contributions. Going forward, Yukon Energy will include this
8 schedule as part of Tab 7 in the next GRA.

9
10 (d)

11
12 Insurance proceeds of \$4.520 million have been received and there are no other amounts
13 outstanding. Yukon Energy did incur \$20,000 of costs relating to the insurance recovery
14 resulting in a net gain of \$4.500 million.

15
16 (e)

17
18 Upon further investigation and analysis, it was concluded the insurance proceeds are
19 directly related to the old Lewes River Boat Lock asset and are not tied to the future build,
20 if any. The Office of the Auditor General of Canada determined that the insurance
21 proceeds were to be recorded as revenue for IFRS purposes. The insurance proceeds
22 are not to be net against the cost of a future Lewes Boat Lock rebuild.

23
24 However, in a scenario where the insurance proceeds were tied to the future Lewes Boat
25 Lock rebuild for regulatory purposes, the impact would include:

- 26 • Increase in depreciation expense for 2025, 2026 and 2027 of approximately \$1.5
27 million each year; and
28 • Reduced AFUDC of \$0.040 million until project completion¹.

29
30 The net impact on ratepayers in the GRA test years of 2025, 2026 and 2027 if insurance
31 proceeds were tied to the future Lewes Boat Lock rebuild would be higher rates resulting
32 from additional revenue requirement of approximately \$1.460 million each year.

¹ Calculated as project ending 2024 WIP of \$1.440 million multiplied by approximate AFUDC rate of 3%.

1 **(f)**

2
3 The proceeds of \$4.520 million from the insurance claim with respect to the Lewes River
4 Boat Lock could be recognized in its entirety as a reduction to depreciation expense.
5 Yukon Energy is proposing to spread the impact over three years to smooth the impact on
6 rates and to show a lower overall rate increase from 2024 to 2027. If the insurance claim
7 was recognized entirely in 2025 as opposed to over three years, revenue requirement for
8 2025 would be reduced by \$3.0 million but would be increased by \$1.5 million in both 2026
9 and 2027.

10
11 The proceeds of \$4.520 million from the insurance claim with respect to the Lewes River
12 Boat Lock should not be recognized in its entirety as a reduction to CWIP as, based on
13 information provided in part (e), the Office of the Auditor General of Canada determined
14 the insurance proceeds should be recognized as revenue and not related to a future asset
15 rebuild.

16
17 **(g)**

18
19 The status of the Lewes River Boat Lock project was provided in the Appendix 5.1B
20 starting on PDF page 301 of the application. In summary, at the time of preparation of the
21 application, the project was put on hold because of the high-cost of the project and the
22 risk-ranking as compared to other high-cost projects.

23
24 Since the application Yukon Energy has been investigating alternatives including the
25 potential for the Lewes River Boat Lock to never be rebuilt. Furthermore, in the Yukon
26 Water Board's decision on the WRGS water licence effective July 31, 2025, it ruled "The
27 Licensee is prohibited from conducting any in-water maintenance, reconstruction of or
28 repairs to the Lewes Boat Lock."².

² Conditions of Water Licence HY24-061 clause 13.

YUB-YEC-1-50 Attachment 1

\$000

Description	Cost at 2024 Year End	2025 Additions	2025 Disposals/ Adjustments	Cost at 2025 Year End	Depreciation Rate (Years)	Depreciation Expense for 2025
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
Customer Contributions	48,356.2	400.0	0.0	48,756.2	**	1,583.3
YDC Contributions	111,211.2	0.0	0.0	111,211.2	40	2,802.5
YG Contributions	13,316.0	0.0	0.0	13,316.0	52	258.2
GIF Funding	71,000.0	0.0	0.0	71,000.0	72	990.7
BESS Contributions	0.0	0.0	0.0	0.0	20	0.0
Total*	243,883.5	400.0	0.0	244,283.5		5,634.6
Deferred Cost Contributions***	2,923.6	62.5	0.0	2,986.1	10/5	298.6
Total Amortization of Contributions						5,933.3

Description	Cost at 2025 Year End	2026 Additions	2026 Disposals/ Adjustments	Cost at 2026 Year End	Depreciation Rate (Years)	Depreciation Expense for 2026
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
Customer Contributions	48,756.2	400.0	0.0	49,156.2	**	1,589.6
YDC Contributions	111,211.2	0.0	0.0	111,211.2	40	2,802.5
YG Contributions	13,316.0	0.0	0.0	13,316.0	52	258.2
GIF Funding	71,000.0	0.0	0.0	71,000.0	72	990.7
BESS Contributions	0.0	16,500.0	0.0	16,500.0	20	412.5
Total*	244,283.5	16,900.0	0.0	261,183.5		6,053.4
Deferred Cost Contributions***	2,986.1	0.0	0.0	2,986.1	10/5	304.9
Total Amortization of Contributions						6,358.3

Description	Cost at 2026 Year End	2027 Additions	2027 Disposals/ Adjustments	Cost at 2027 Year End	Depreciation Rate (Years)	Depreciation Expense for 2027
A	B	C	D	E=B+C-D	F	G=B/F+C/2/F
Customer Contributions	49,156.2	400.0	0.0	49,556.2	**	1,596.3
YDC Contributions	111,211.2	0.0	0.0	111,211.2	40	2,802.5
YG Contributions	13,316.0	0.0	0.0	13,316.0	52	258.2
GIF Funding	71,000.0	0.0	0.0	71,000.0	72	990.7
BESS Contributions	16,500.0	0.0	0.0	16,500.0	20	825.0
Total*	261,183.5	400.0	0.0	261,583.5		6,472.7
Deferred Cost Contributions***	2,986.1	0.0	0.0	2,986.1	10/5	211.0
Total Amortization of Contributions						6,683.7

Notes:

* The total is excluding Lewes River Boat Lock Proceeds as the amortization of these proceeds is shown as a separate line item in Table 3.13. The variance of \$4.5 million in the total capital related contributions in service in Table 5.1 [e.g., \$248.784 million for 2025 in Table 5.1] compared to this table [\$244.284 million] reflects Lewes River Boat Lock Proceeds.

** The customer contributions include contributions from residential, commercial and industrial customers. The amortization rates are based on the life of the underlying asset [e.g., VG related contributions over the mine life, etc.].

*** The details of the calculations are provided in Schedule 3B in Tab 7 [DSM over 10 years, other contributions over 5 years].

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 95-96

2
3 **ISSUE:** Hearing Cost Reserve Account

4
5 **QUOTE:** Until there is a change in the regulatory process, costs are expected to
6 remain high. Yukon Energy has taken steps to reduce its costs such as
7 internal preparation of its GRA's, submission of a longer-term GRA and
8 reduction of administration costs. However, Yukon Energy cannot
9 control intervenor costs and effects on Yukon Energy and Board costs
10 for questions that provide no value to the proceeding. As requested in
11 the 2023/24 GRA, Yukon Energy is requesting a limit on intervenor
12 questions to minimize risk of irrelevant or insignificant questions.

13
14 **QUESTION:**

- 15
16 a) Referring to the quote above, aside from limiting intervenor questions, what type
17 of change in regulatory process is YEC referring to?
18
19 b) Referring to the quote above, please identify and provide a quantification of how
20 YEC has reduced administration costs related to its Hearing Cost Reserve
21 Account.
22
23 c) With respect to regulatory efficiency, has YEC ever conducted a study or review
24 of the types of information that would best support its application and assist parties
25 in examining and understanding the details of its requested revenue requirement?
26

27 **ANSWER:**

28
29 **(a)**

30
31 The Yukon Government is leading a review of the *Public Utilities Act* with the purpose of
32 ensuring an effective and efficient process for regulating electricity in the Yukon. Yukon
33 Energy is referring to changes that may occur as a result of this review.
34

35 **(b)**

36
37 Yukon Energy has reduced or attempted to reduce administrative costs in several ways,
38 including the following:

- Reducing travel for consultants and staff, saving \$5,000;
- Binders for Board and intervenors were prepared internally rather than contracted out professionally, saving \$5,000;
- Rented a smaller facility for the GRA workshop, saving \$2,000; and
- Eliminated media/public speaking training saving \$5,000.

(c)

Yukon Energy has not conducted any formal study with respect to regulatory efficiency. Yukon Energy did hire a Regulatory Planner in 2022, and that position has assisted in providing guidance as to what is done in other jurisdictions. In preparation for this application, internal Yukon Energy staff reviewed applications from other jurisdictions:

- A review of Northwest Territories Power Corporation resulted in Yukon Energy adjusting the minimum capital project balance detail requirement from \$100,000 to \$400,000;
- A review of utilities in the Electricity Canada group assisted in Yukon Energy increasing the number of test years from two to three;
- A review of Nova Scotia Power Corp and ATCO Electric Yukon resulted in Yukon Energy adjusting information provided in business cases for capital projects;
- A review of BC Hydro assisted in preparation of Yukon Energy's new simplified Criteria for Capitalization policy and minimized regulatory variances with IFRS; and
- Yukon Energy met with intervenors prior to submission.

REFERENCE: YEC 2025-2027 Application, PDF page 98

ISSUE: Vegetation Management Deferral

QUOTE:

3.4.4.2 Vegetation Management Deferral

Board Order 2013-01 required Yukon Energy to create a vegetation management deferral account to defer brushing costs in excess of 2011 actual brushing costs. As part of the 2017/18 GRA, the Board approved amortization of the 2016 balance of \$2.215 million over a 10-year period (\$0.222 million per year from 2017 through 2026) and directed that deferral of these costs is no longer required. Yukon Energy is not proposing any changes for the test years. This deferral account is scheduled to expire on December 31, 2026. Table 3.13.1.3 shows the deferred vegetation management continuity schedule.

**Table 3.13.1.3:
Deferred Vegetation Management Continuity Schedule
(\$000)**

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
Opening Balance	\$ 886	\$ 665	\$ 886	\$ 665	\$ 443	\$ 222	\$ -
Annual Deferred Costs	0	0	0	0	0	0	0
Annual Amortization	(222)	(222)	(222)	(222)	(222)	(222)	0
Closing Balance	\$ 665	\$ 443	\$ 665	\$ 443	\$ 222	\$ -	\$ -

QUESTION:

- a) Please explain why YEC considers that the Vegetation Management Deferral Account will be “expired” as of December 31, 2026 as opposed to the deferral amount becoming fully amortized.
- b) What is the significance of the account being expired rather than not being required until some future point in time.

ANSWER:

(a) and (b)

Yukon Energy has no issues with using the term “becoming fully amortized” rather than “expired”. Yukon Energy considered these terms to mean the same thing. Yukon Energy does not believe there is any significance as the Board can direct Yukon Energy to activate a new deferral account or reactivate a prior deferral account any time in the future.

REFERENCE: YEC 2025-2027 Application, Appendix 3.2: Employee Complement Addition Justifications, PDF pages 118-144;
Tab 3 tables: Table 3.4 Employee Complement History, Table 3.4.1 Employee Complement Changes from 2027 GRA

ISSUE: Employee complement and Full Time Equivalent (FTE) information

QUOTE: PDF page 119:

“This position will address the strategic priority of Invest in people with the action to attract, develop and retain talent. This position will also address the strategic priority of Plan the renewables of tomorrow.”

Tab 3 tables, Table 3.4:

**Table 3.4
Employee Complement History**

	Approved 2023	Approved 2024	Actual 2023	Preliminary Actual 2024	Proposed 2025	Proposed 2026	Proposed 2027
President & Corporate Services	3.10	3.10	3.34	3.29	3.10	3.10	4.10
Government Relations	1.00	2.00	1.00	-	-	-	-
Business Development	1.00	1.00	1.00	-	-	-	-
Communications & Customer Service	3.60	3.60	4.60	-	-	-	-
People & Culture	2.00	2.00	2.00	-	-	-	-
Partnerships & Business Services				15.05	15.25	16.50	18.00
Resource Planning, Environment, Health & Safety	10.60	11.13	11.10	11.98	12.60	13.85	13.85
Finance & Procurement	19.29	20.29	19.41	13.79	13.79	14.79	14.79
Operations	51.96	53.20	51.46	55.10	59.95	63.60	64.45
Engineering Services	20.50	23.50	19.75	24.25	24.25	28.00	29.25
Total	113.05	119.81	113.66	123.46	128.94	139.84	144.44
Vacant	9.00	9.00	12.32	7.99	9.00	9.00	9.00
Filled	104.05	110.81	101.34	115.47	119.94	130.84	135.44

Note:

1. The employee complement numbers are net of allocation to YDC.

2. In 2024, the positions under Government Relations, Business Development, Communications & Customer Service, People & Culture and IT were transferred to Partnerships & Business Services. Please see Table 3.4.1 for details.

PREAMBLE: At various points in Appendix 3.2, YEC states that the position question will address the strategic priority “Invest in people.”⁵ YEC also identifies a “strategic priority of Plan the renewables of tomorrow.”⁶ Appendix 3.2 also provides by Department, a list of the planned additions by position “title.”

⁵ YEC 2025-2027 Application, Appendix 3.2: Employee Complement Addition Justifications, PDF pages 119, 128, 130, 131, 134, 136, 140, 142 and 144.

⁶ YEC 2025-2027 Application, Appendix 3.2: Employee Complement Addition Justifications, PDF pages 119 and 142.

1 **QUESTION:**

- 2
- 3 a) Please provide details of YEC's "strategic priority of Invest in people."
- 4
- 5 b) Please provide details of YEC's "strategic priority of Plan the renewables of
- 6 tomorrow."
- 7
- 8 c) How do the objectives of each of the strategic priorities identified in parts (a) and
- 9 (b), align with the provision of utility services.
- 10
- 11 d) Referring to Table 3.4, it appears that several groups or departments have been
- 12 amalgamated into a single group "Partnerships & Business Services." Please
- 13 explain the significance of the change in reporting structure and why it was
- 14 necessary to do so. How does the change assist YEC in carrying out the duties of
- 15 its utility function?
- 16
- 17 e) Please provide an organization chart for each test year that will assist in
- 18 understanding the composition of each department noted on Table 3.4 by the
- 19 position titles used in Appendix 3.2.
- 20
- 21 f) Of the planned additions to employee complement, for each test year, please
- 22 clearly identify which planned additions to employee complement are intended to
- 23 replace the need to rely on an external contractor or consultant to perform the
- 24 required task. Please also provide a reference to where this expected outcome
- 25 can be observed in YEC's application.
- 26

27 **ANSWER:**

28

29 **(a)**

30

31 One of Yukon Energy's strategic priorities in the next five years is to "Invest in People and

32 Technology". Key actions in the strategy are to:

33

- 34
 - Attract, develop and retain top talent;
 - Improve business processes with new and existing technologies; and
 - Continue to build and utilize our assets management program to improve asset
- 35 decision making and realize value from our assets.
- 36
- 37

1 Positions noted in section 3.2 of the application that align with this strategic priority help
2 advance one or more of the above actions (i.e., talent, technologies and/or asset
3 management).

4
5 **(b)**
6

7 Yukon Energy's strategic priority of "Plan the renewables of tomorrow" includes key
8 actions such as:

- 9
- 10 • Continuing to explore options to advance renewable electricity in the Yukon;
11 and
12
 - 13 • Support the Yukon Development Corporation as they lead the development of
14 a resource plan that will identify the resources needed to meet electricity
15 demands and climate goals by 2050.
16

17 **(c)**
18

19 The strategic priorities identified in parts (a) and (b) align with the provision of utility
20 services as follows:

21
22 Investing in People:

23 Attracting, developing and retaining top talent is key for Yukon Energy as the utility sector
24 is a highly competitive market made of many professions and/or trades with unique skill
25 sets. As an organization located North of 60, Yukon Energy must also provide competitive
26 wages, benefits, employee training and development, and career opportunities to compete
27 in a remote jurisdiction with a high cost of housing and living.
28

29 Retaining top talent is also more cost effective than recruiting and relocating new staff and
30 provides for greater efficiency in the organization and service to customers. Retention
31 strategies need to address areas of the business where there are high levels of overtime,
32 a single resource in a highly specialized unique role with no back-fill or where more
33 resources are needed to complete increased workloads. These strategies may include the
34 employment of contractors at specific times of high work volumes, or the addition of more
35 staff to reduce overtime or learn unique areas of the business. These tactics also help
36 promote a healthier workforce where risks of employee-burnout, use of sick time and
37 disability benefits are reduced, and voluntary turnover are reduced.

1 Planning the renewables of tomorrow:

2 As a utility, Yukon Energy's purpose is to ensure the ongoing supply and delivery of safe
3 and reliable electricity to Yukoners. This includes meeting the electricity needs of
4 Yukoners today and proactively forecasting future electricity needs and planning the
5 supply resources, system improvements and emerging technologies needed to support
6 those needs. This is especially important for Yukon Energy at this time as the demand for
7 electricity in the Yukon is growing faster than new sources of firm, renewable winter power
8 can be built. Without proactive planning and actively working with partners and
9 governments to advance those plans, the chances of an electricity deficit in the Yukon are
10 likely.

11
12 **(d)**
13

14 The change in reporting structure was necessary to provide consistent leadership,
15 strategic direction and support to the Government Relations, Communications, Customer
16 Service, Business Development, People & Culture and Information Technology teams.

17
18 Prior to the amalgamation of the group under the "Partnerships and Business Services"
19 banner, the different teams reported to two different Vice Presidents and in the case of
20 People and Culture, to the President and CEO, despite each of the teams being a "service
21 provider" to Yukon Energy's external facing customers (i.e., Yukoners) or internal
22 customers (i.e., employees). This led to an inconsistent approach to internal and external
23 communications and a fragmented delivery of corporate strategy.

24
25 Now, under the leadership of one Vice President, the individual teams can realize
26 efficiencies in their service delivery approach. Team leaders regularly meet to discuss
27 internal and external communication needs, opportunities and business strategies. Teams
28 are now able to leverage technologies, materials and staff more effectively and efficiently
29 than before. For example, communications staff are now better equipped and readily
30 available to support the customer service team during times when there is a high volume
31 of calls; technologies used for notifying external customers of planned outages are now
32 also used to notify internal staff of potential emergencies; public open houses also now
33 include information about customer billing; technologies used in IT to track information
34 requests are now being piloted in the customer service team, etc.

35
36 Optimizing services for multiple purposes and sharing internal resources to deliver similar
37 services is important to a utility as it helps reduce the pressure for increased head count
38 and O&M budgets.

(e)

Please see Attachment 1 to this response. Organization charts provided in Attachment 1 are as outlined below.

Department	Proposed 2025	Proposed 2026	Proposed 2027
President & Corporate Services	Attachment 1.1 (e1)	Attachment 1.1 (e2)	Attachment 1.1 (e3)
Partnerships & Business Services	Attachment 1.2 (e4)	Attachment 1.2 (e5)	Attachment 1.2 (e6)
Resource Planning, Environment, Health & Safety	Attachment 1.3 (e7)	Attachment 1.3 (e8)	Attachment 1.3 (e9)
Finance & Procurement	Attachment 1.4 (e10)	1.4 Attachment (e11)	1.4 Attachment (e12)
Operations	1.5 Attachment (e13)	1.5 Attachment (e14)	1.5 Attachment (e15)
Engineering Services	1.6 Attachment (e16)	1.6 Attachment (e17)	1.6 Attachment (e18)

(f)

At a high-level, the increased employee complement is necessary to manage the higher workload and ensure that essential tasks, which would otherwise go unfinished due to limited resources, can be completed. Therefore, as Yukon Energy has determined the work that needs to be done, if the positions were not filled by FTEs, the work would all have to be done by contractors.

The employee complement addition justifications in Appendix 3.2 point out several specific additions that will replace work of existing contractors. These include:

- Training Coordinator;
- Apprentice Power Line Technician;
- Permitting and Monitoring Coordinator;
- Junior Draftsperson;
- Electrical Engineer; and
- EAM IT Systems Support.

YUB-YEC-1-53 ATTACHMENT 1

ATTACHMENT 1.1
PRESIDENT & CORPORATE SERVICES



Figure e1: President & Corporate Services, Proposed 2025

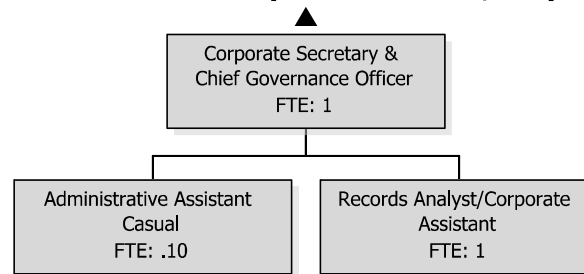




Figure e2: President & Corporate Services, Proposed 2026

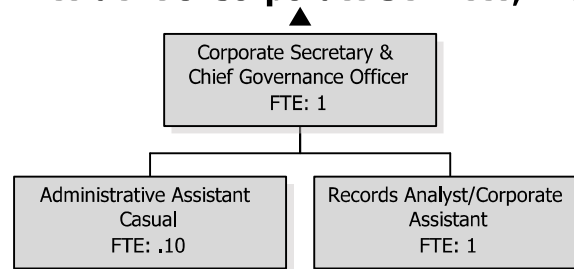
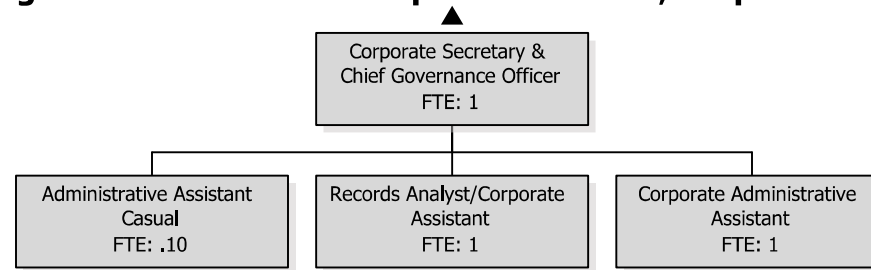


**Figure e3: President & Corporate Services, Proposed 2027**

ATTACHMENT 1.2
PARTNERSHIPS & BUSINESS SERVICES

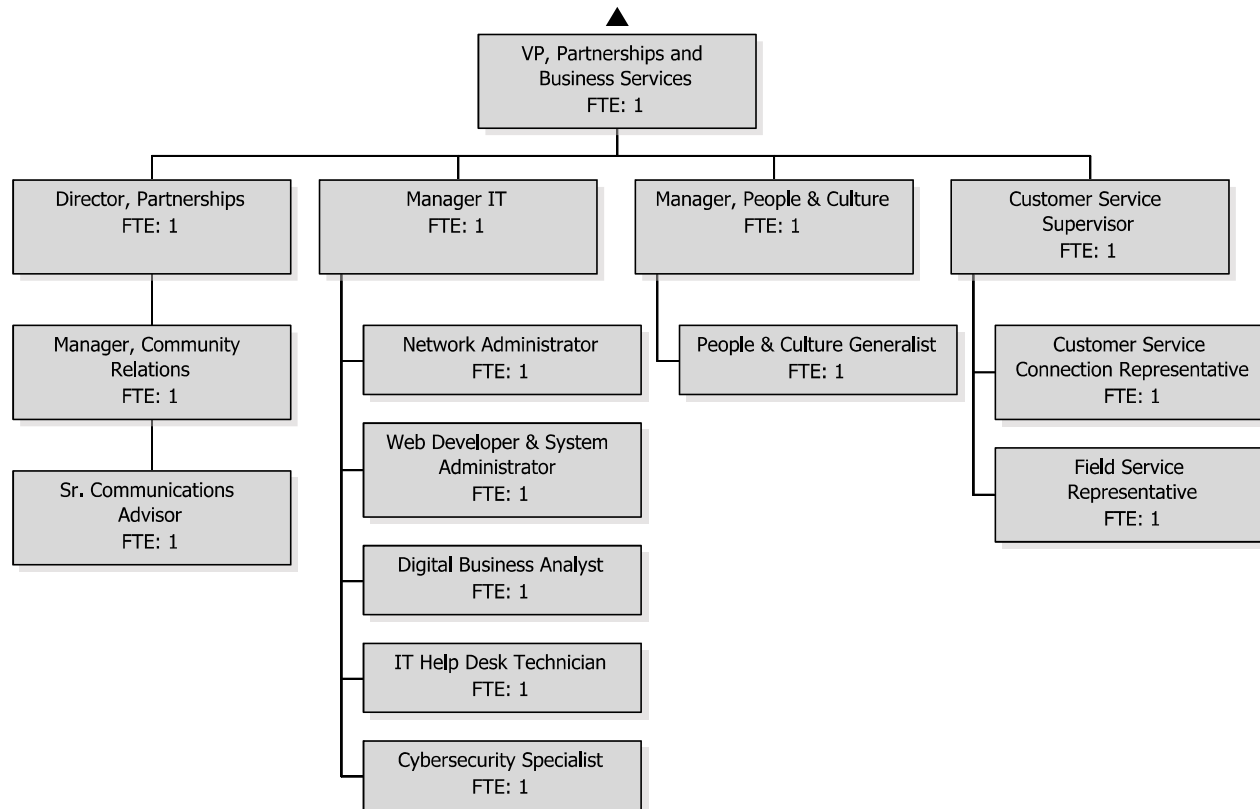
**Figure e4: Partnerships & Business Services, Proposed 2025**

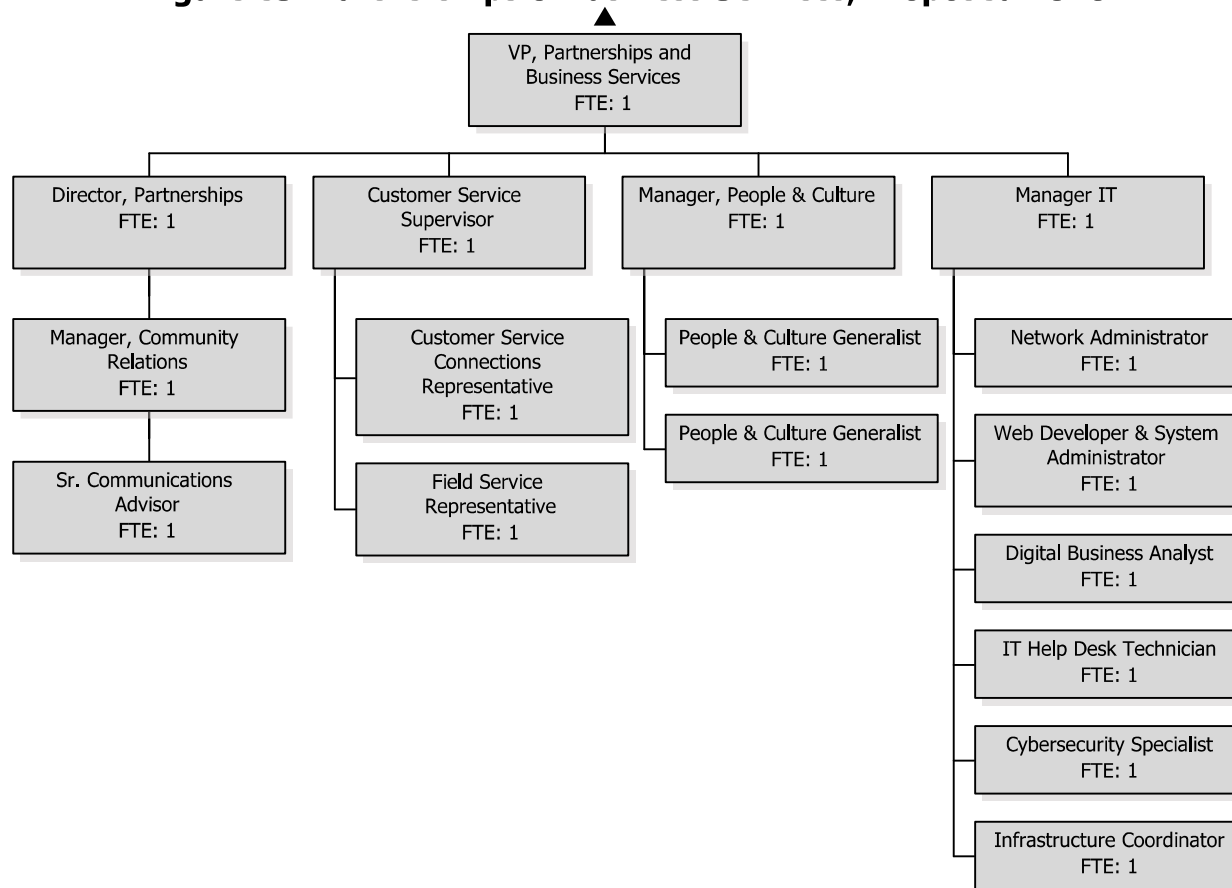
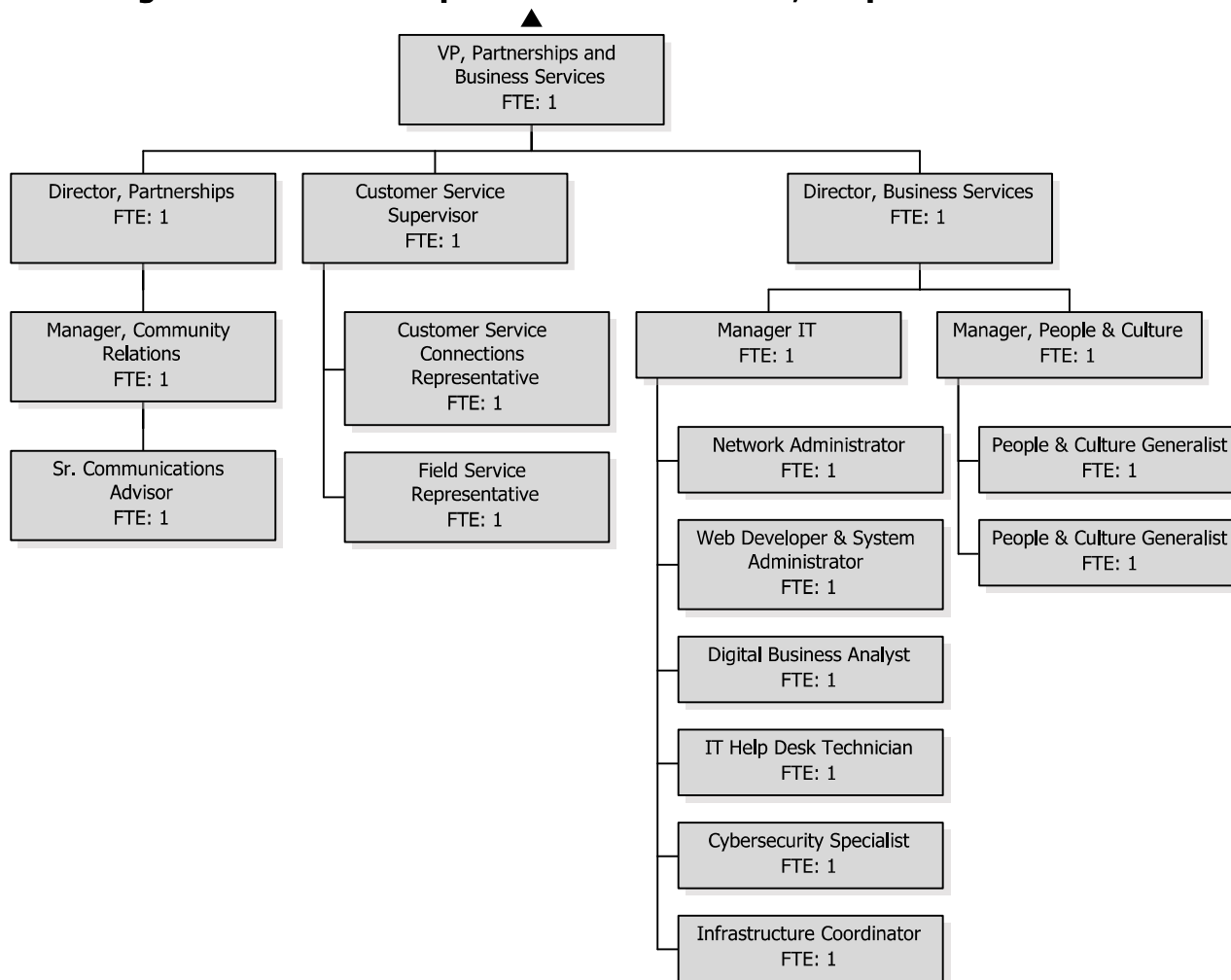
**Figure e5: Partnerships & Business Services, Proposed 2026**

Figure e6: Partnerships & Business Services, Proposed 2027



ATTACHMENT 1.3
RESOURCE PLANNING, ENVIRONMENT,
HEALTH & SAFETY

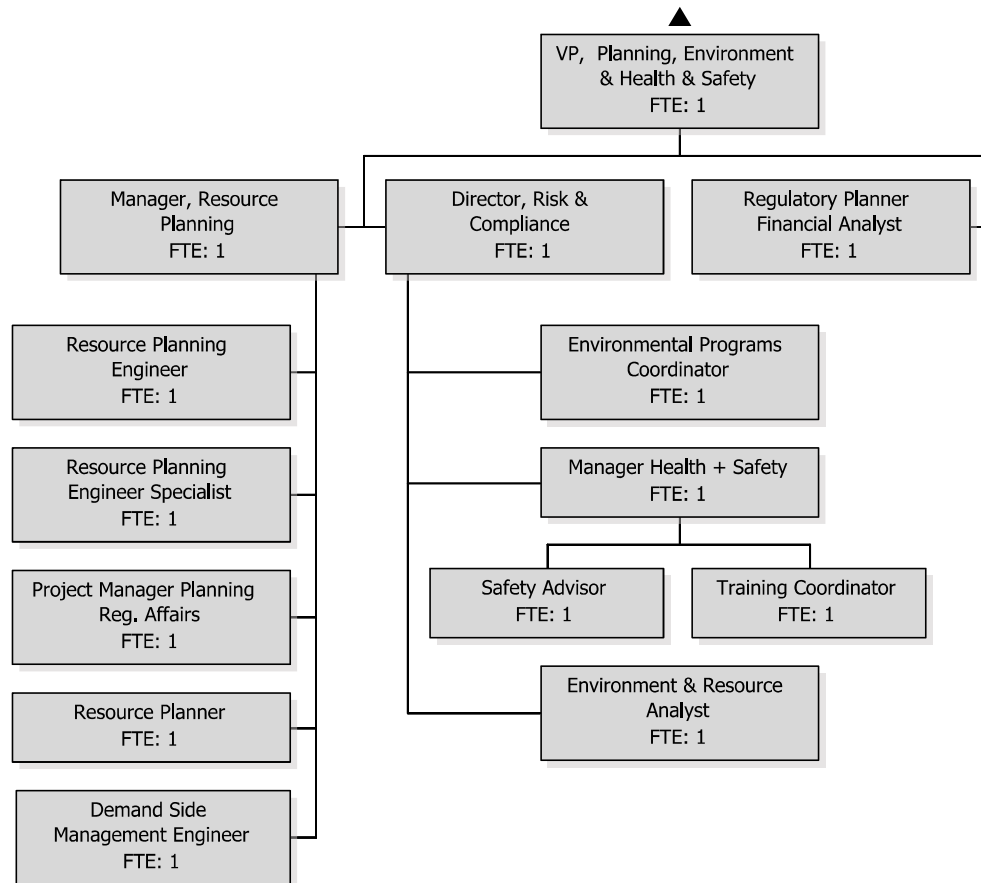
**Figure e7: Resource Planning, Environment, Health & Safety, Proposed 2025**

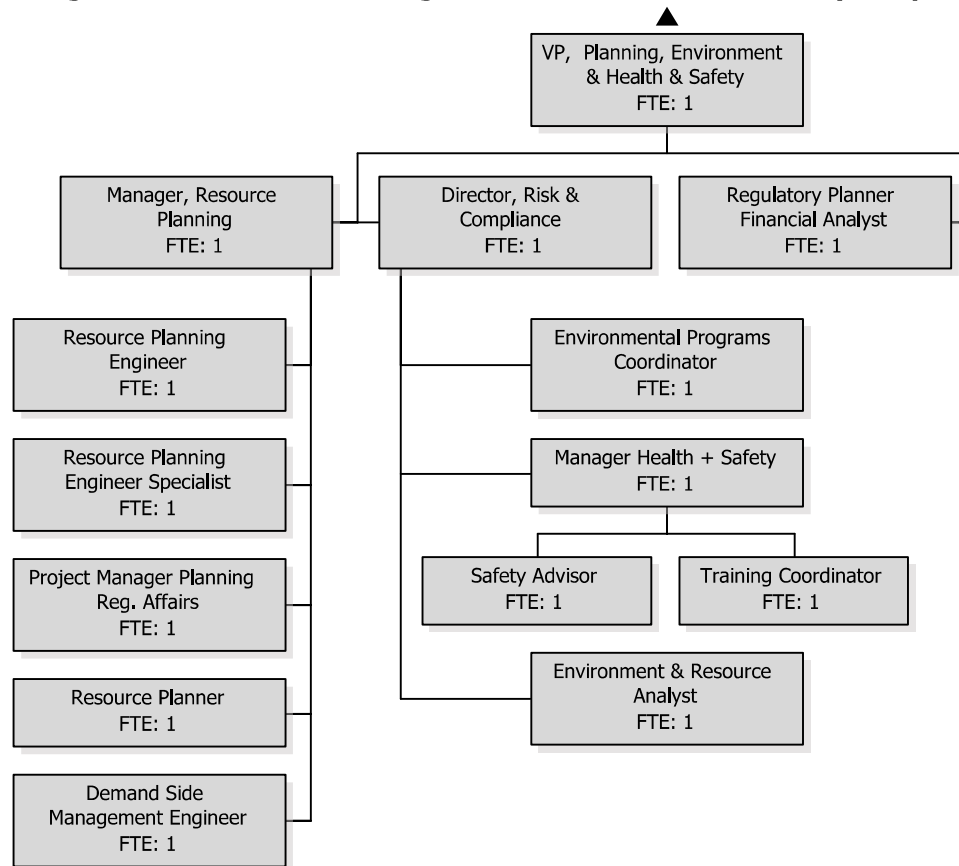
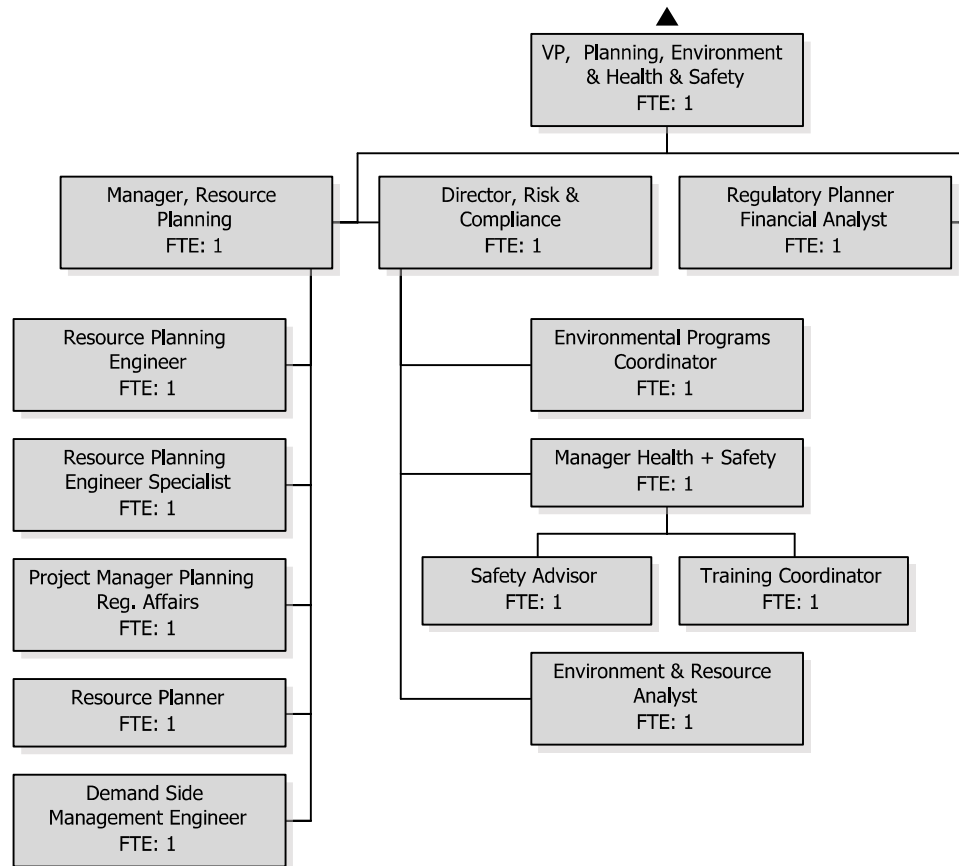
**Figure e8: Resource Planning, Environment, Health & Safety, Proposed 2026**

**Figure e9: Resource Planning, Environment, Health & Safety, Proposed 2027**

ATTACHMENT 1.4

FINANCE & PROCUREMENT

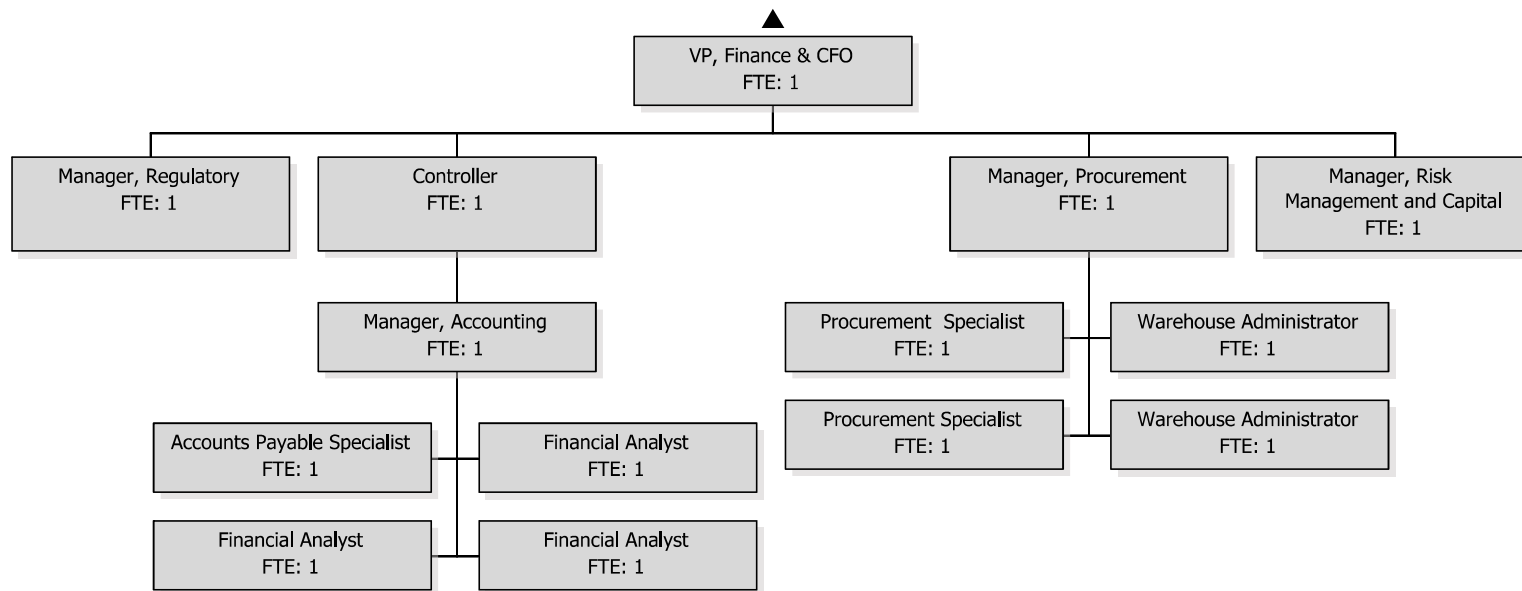
**Figure e10: Finance & Procurement, Proposed 2025**

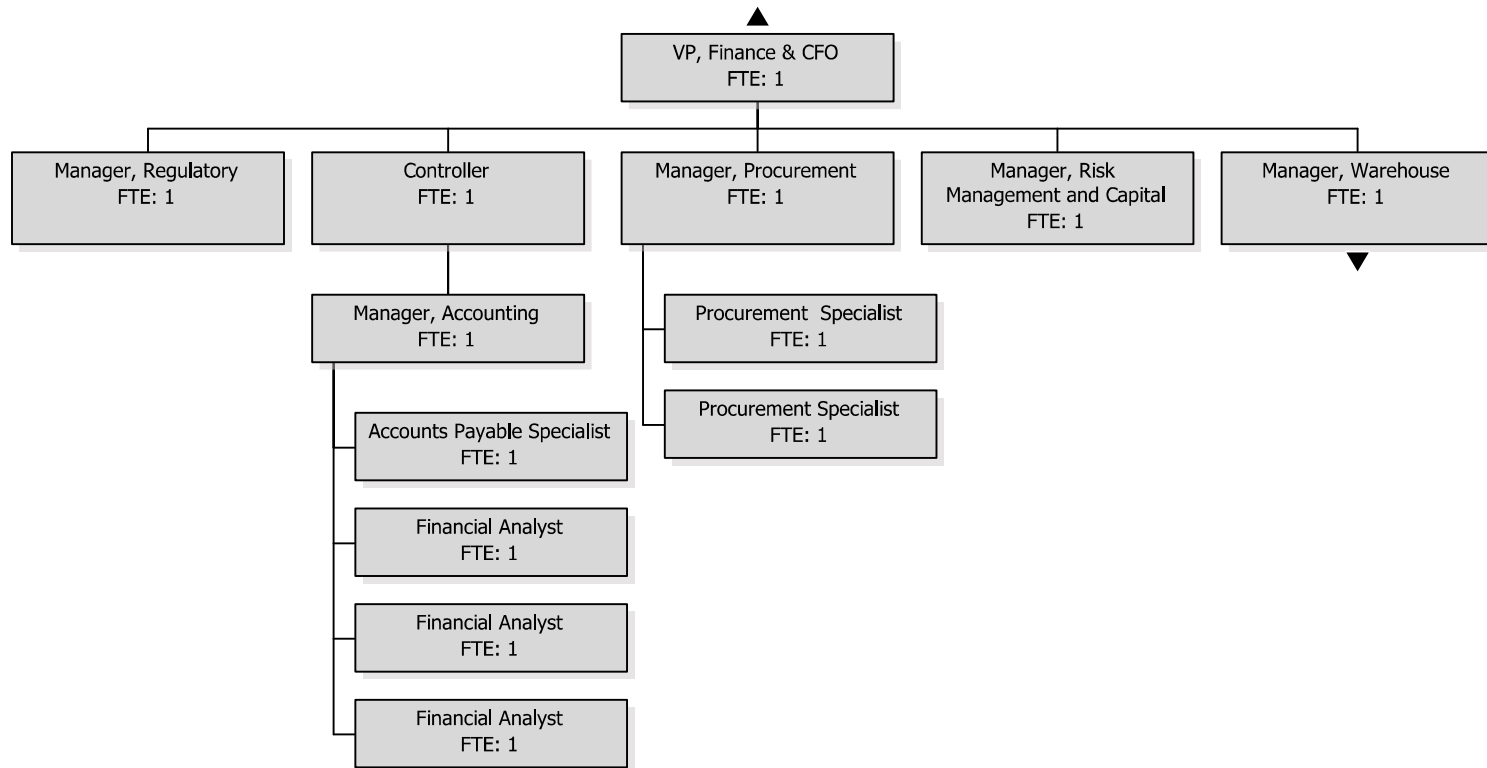
**Figure e11: Finance & Procurement, Proposed 2026**



Figure e11.1: Finance & Procurement, Proposed 2026

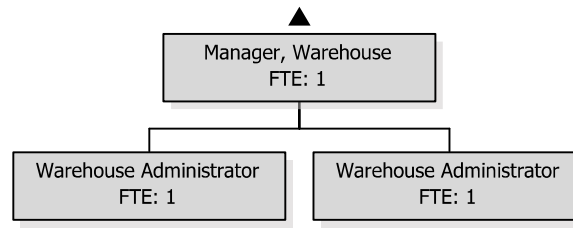




Figure e12: Finance & Procurement, Proposed 2027

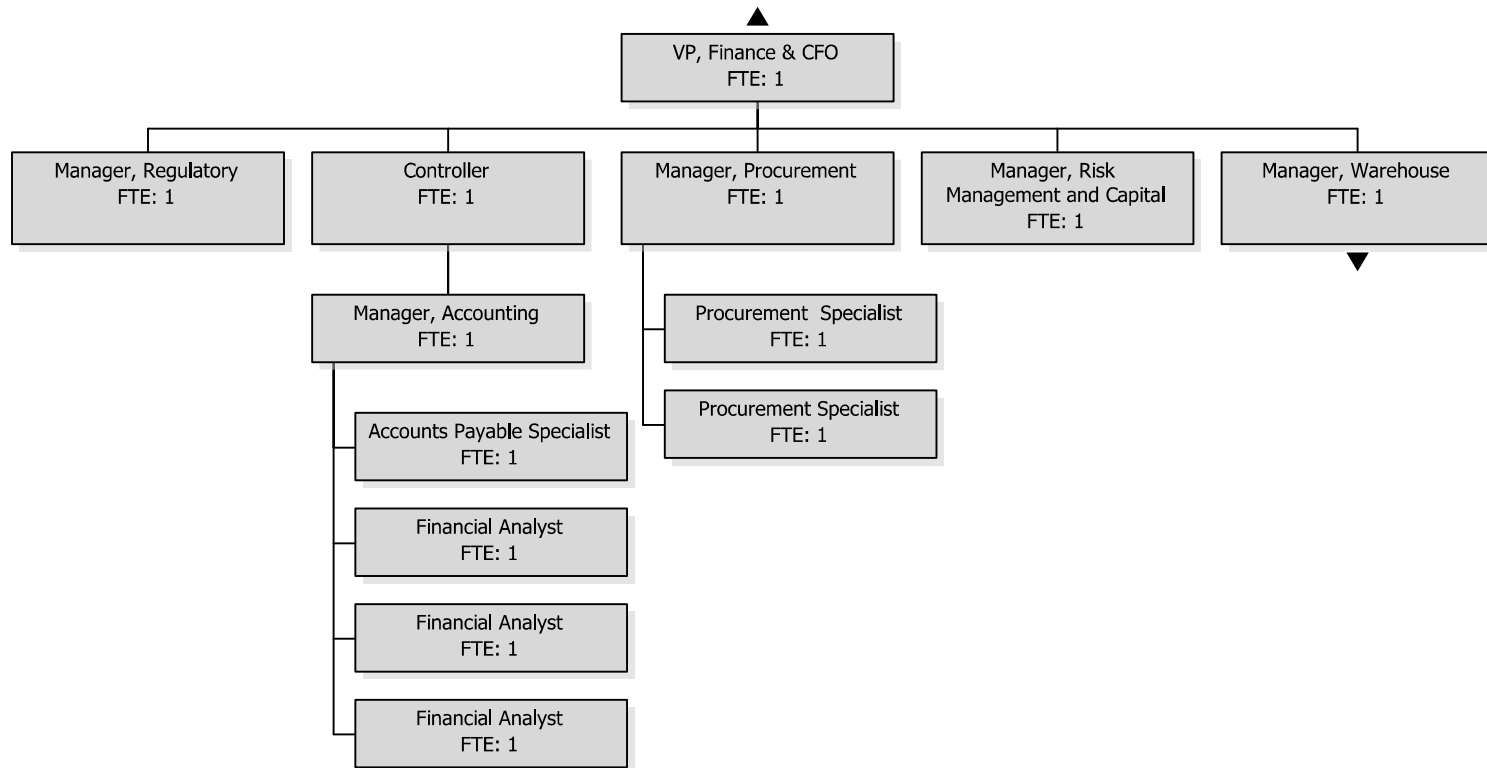
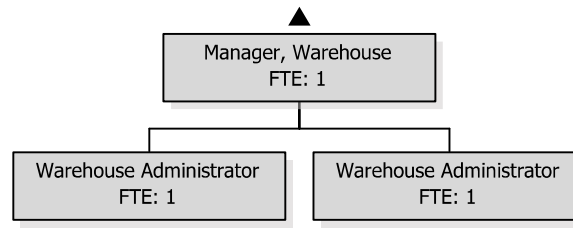




Figure e12.1: Finance & Procurement, Proposed 2027



ATTACHMENT 1.5 OPERATIONS



Figure e13: Operations, Proposed 2025

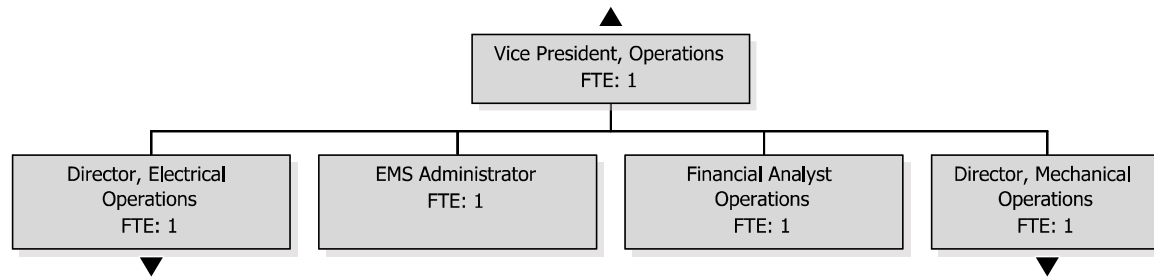


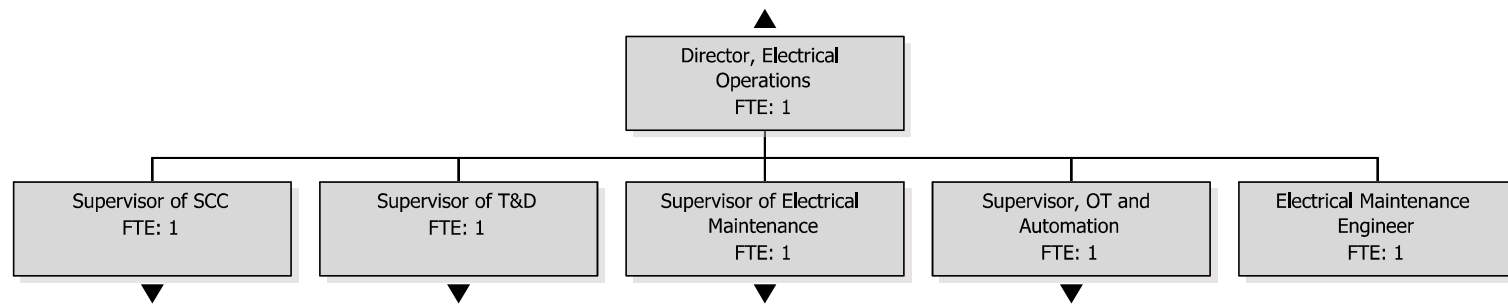
**Figure e13.1: Operations, Proposed 2025**

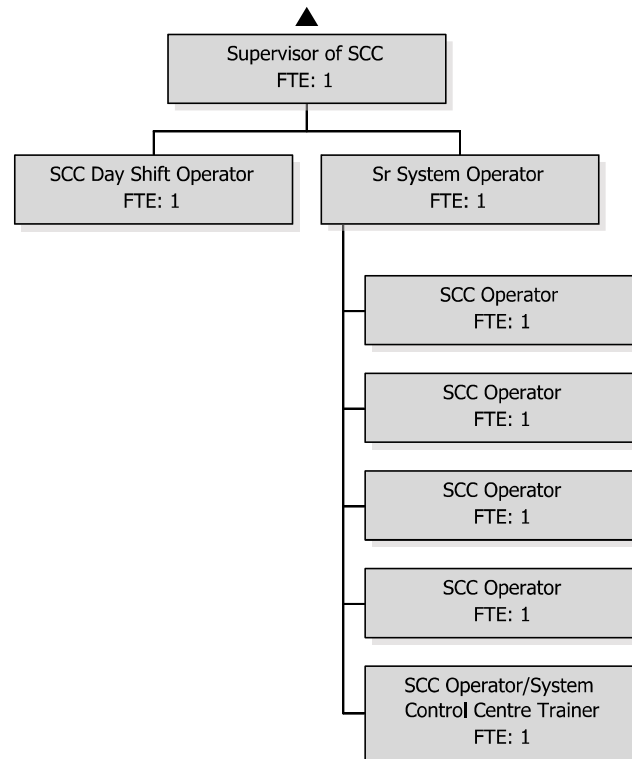
**Figure e13.1.1: Operations, Proposed 2025**

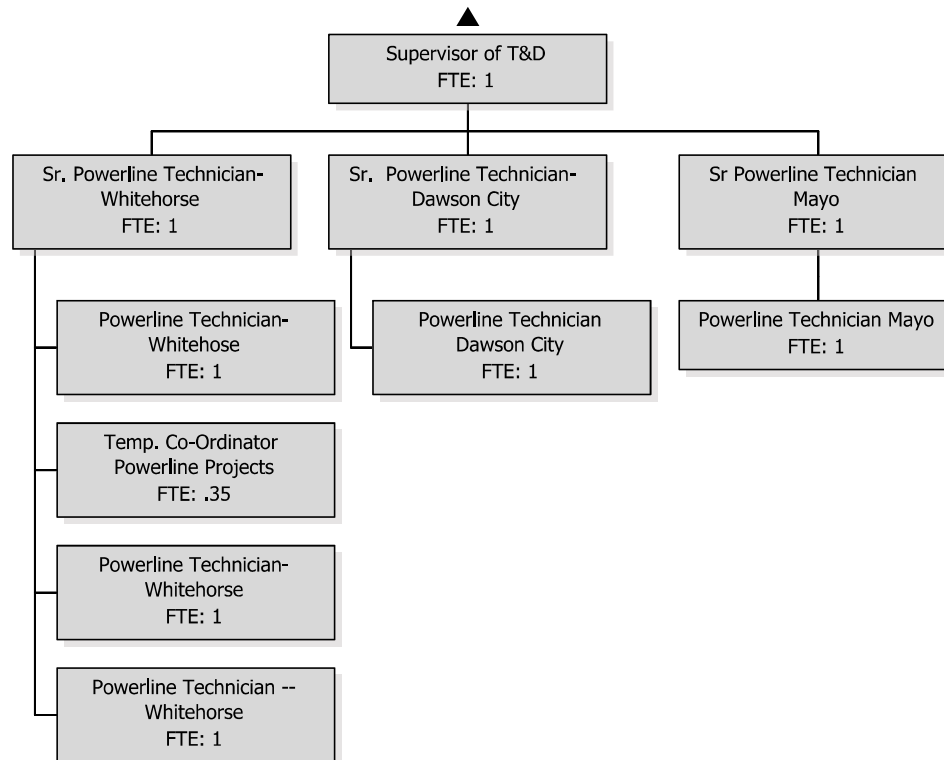
**Figure e13.1.2: Operations, Proposed 2025**

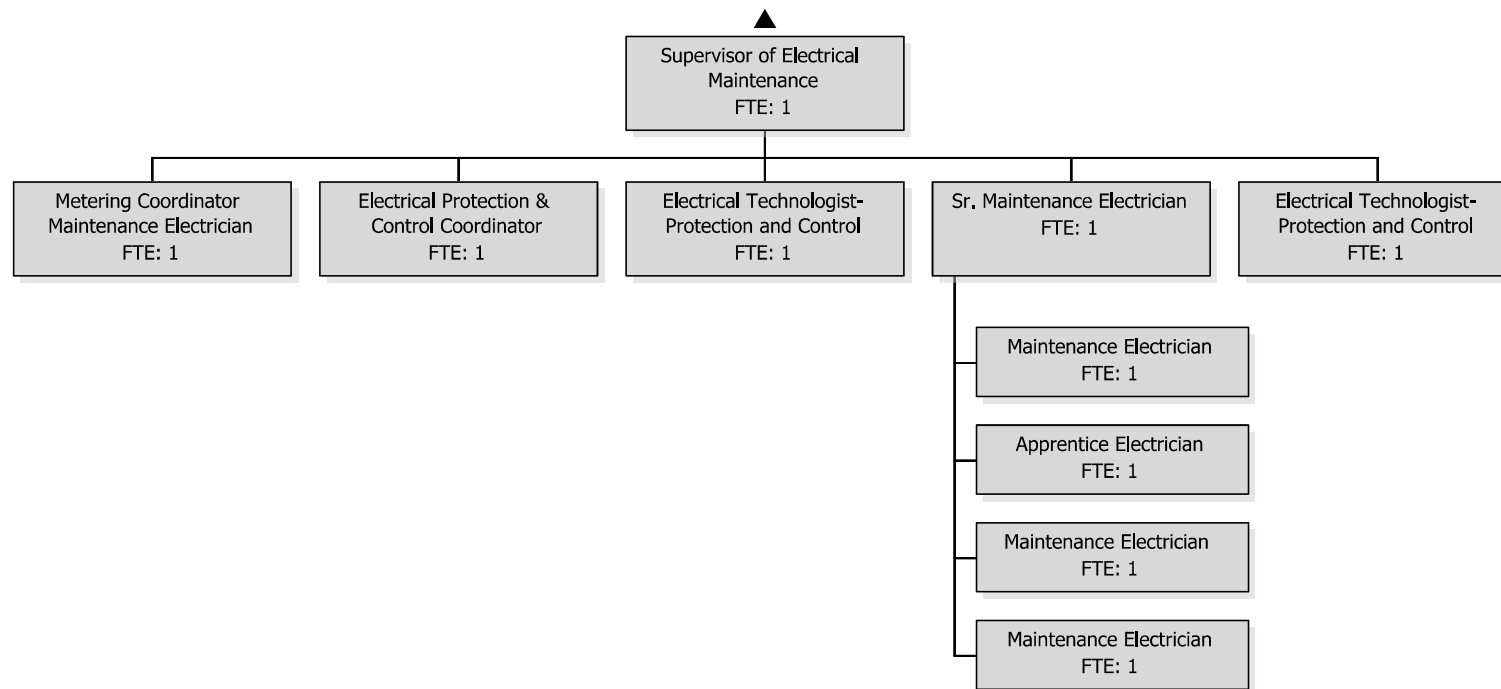
**Figure e13.1.3: Operations, Proposed 2025**

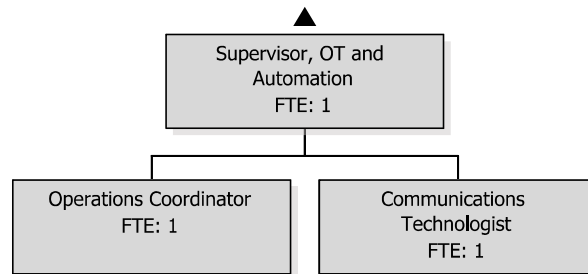
**Figure e13.1.4: Operations, Proposed 2025**



Figure e13.2: Operations, Proposed 2025

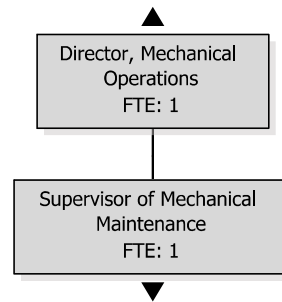


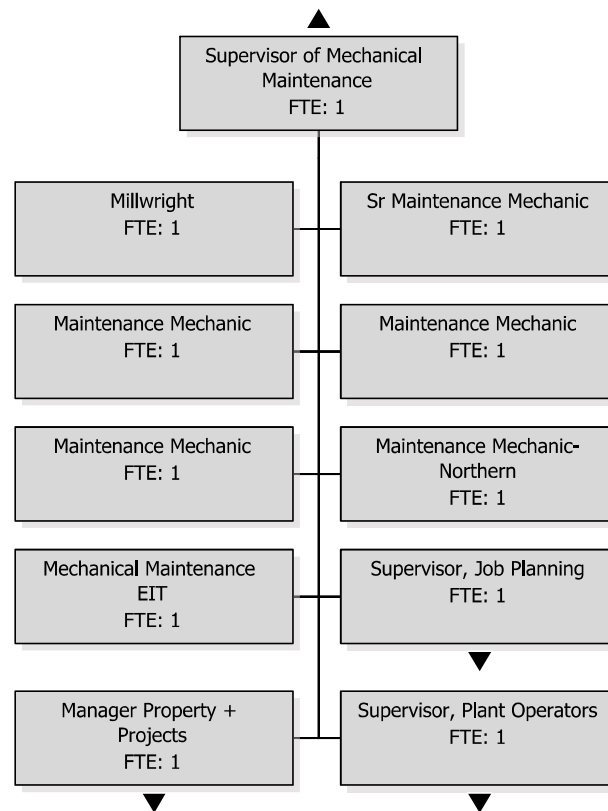
**Figure e13.2.1: Operations, Proposed 2025**



Figure e13.2.1.1: Operations, Proposed 2025

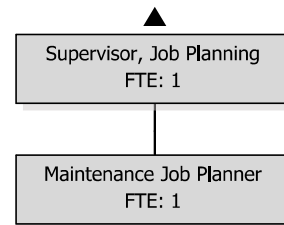




Figure e13.2.1.2: Operations, Proposed 2025

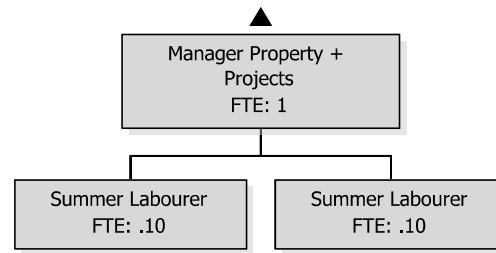


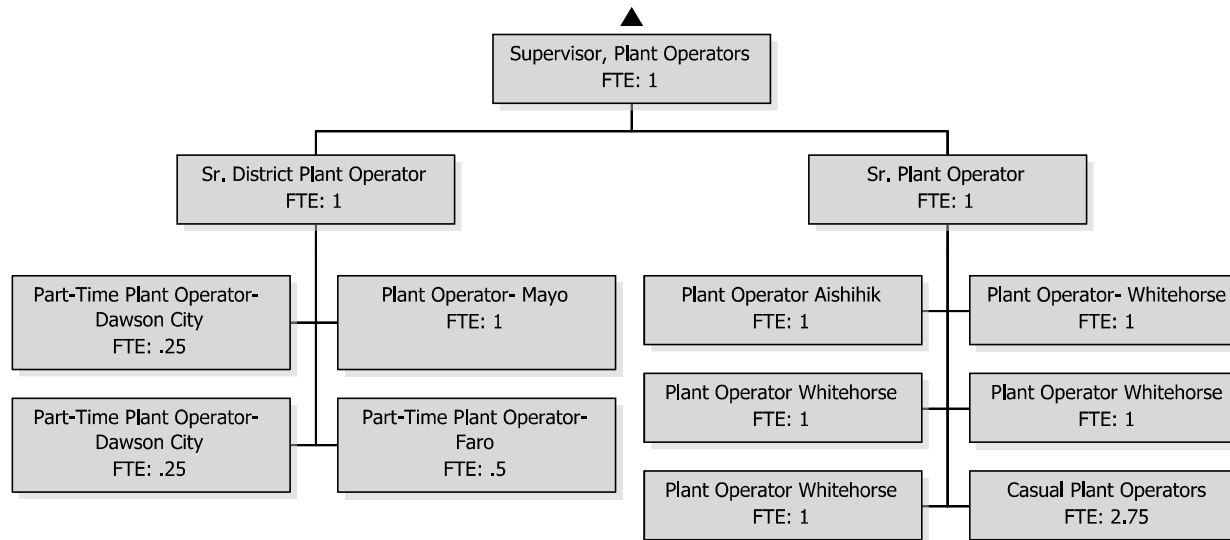
**Figure e13.2.1.3: Operations, Proposed 2025**

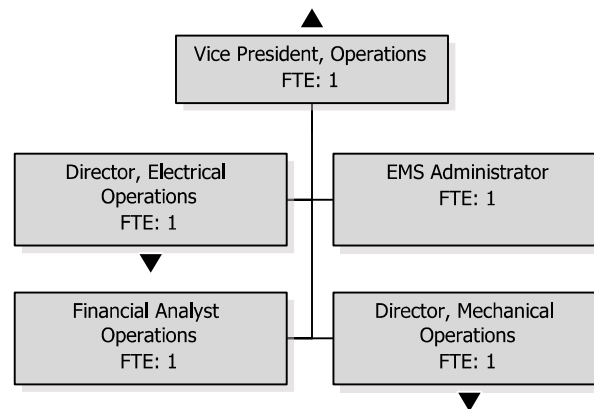
**Figure e14: Operations, Proposed 2026**

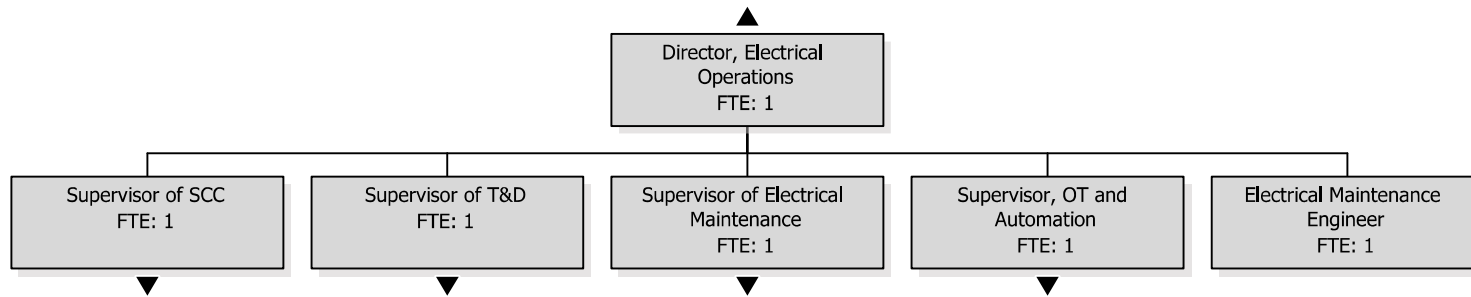
**Figure e14.1: Operations, Proposed 2026**



Figure e14.1.1: Operations, Proposed 2026

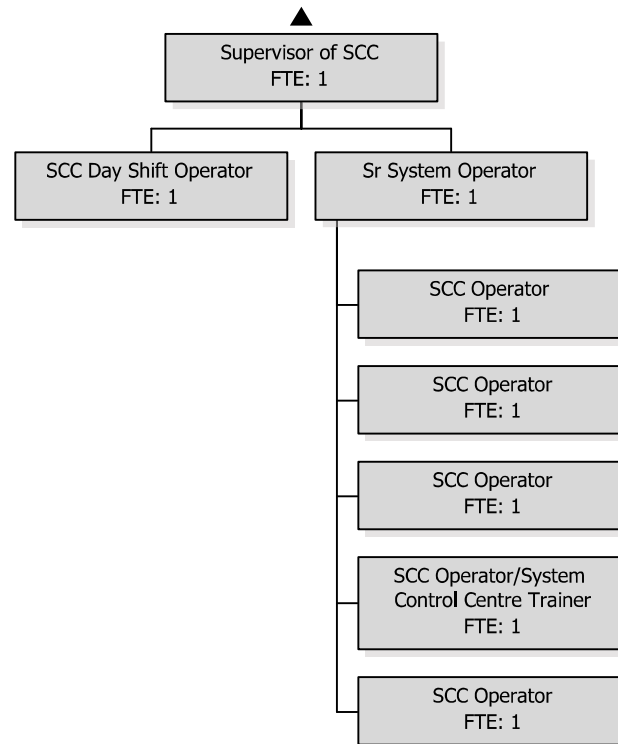




Figure e14.1.2: Operations, Proposed 2026

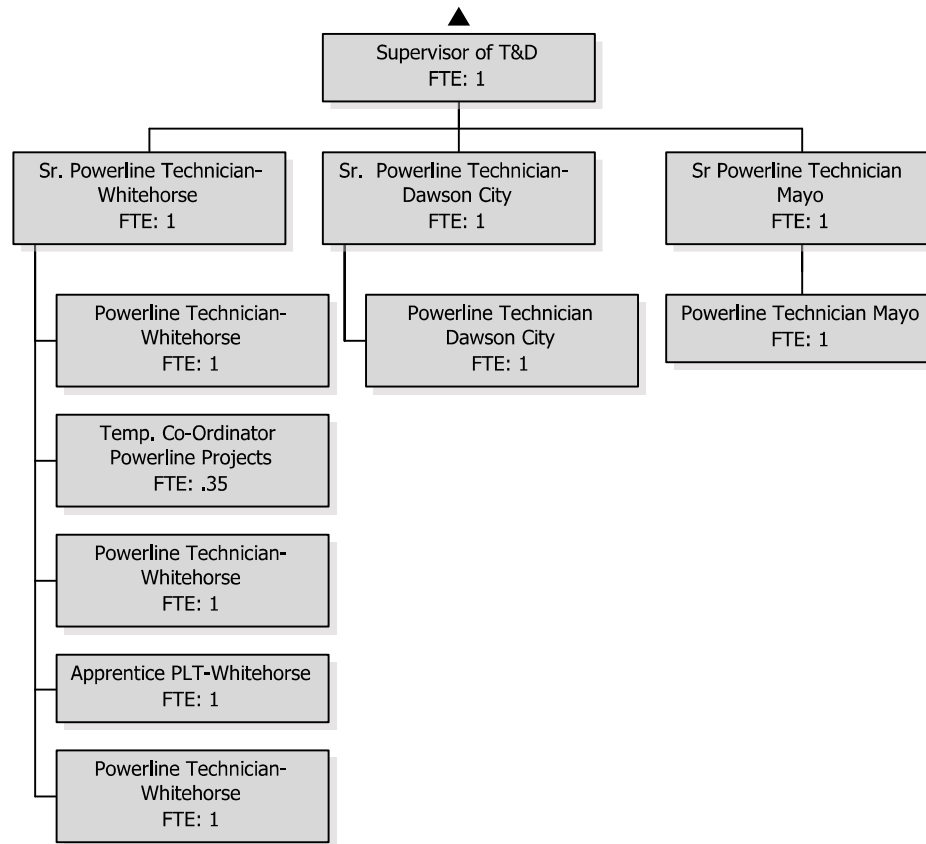


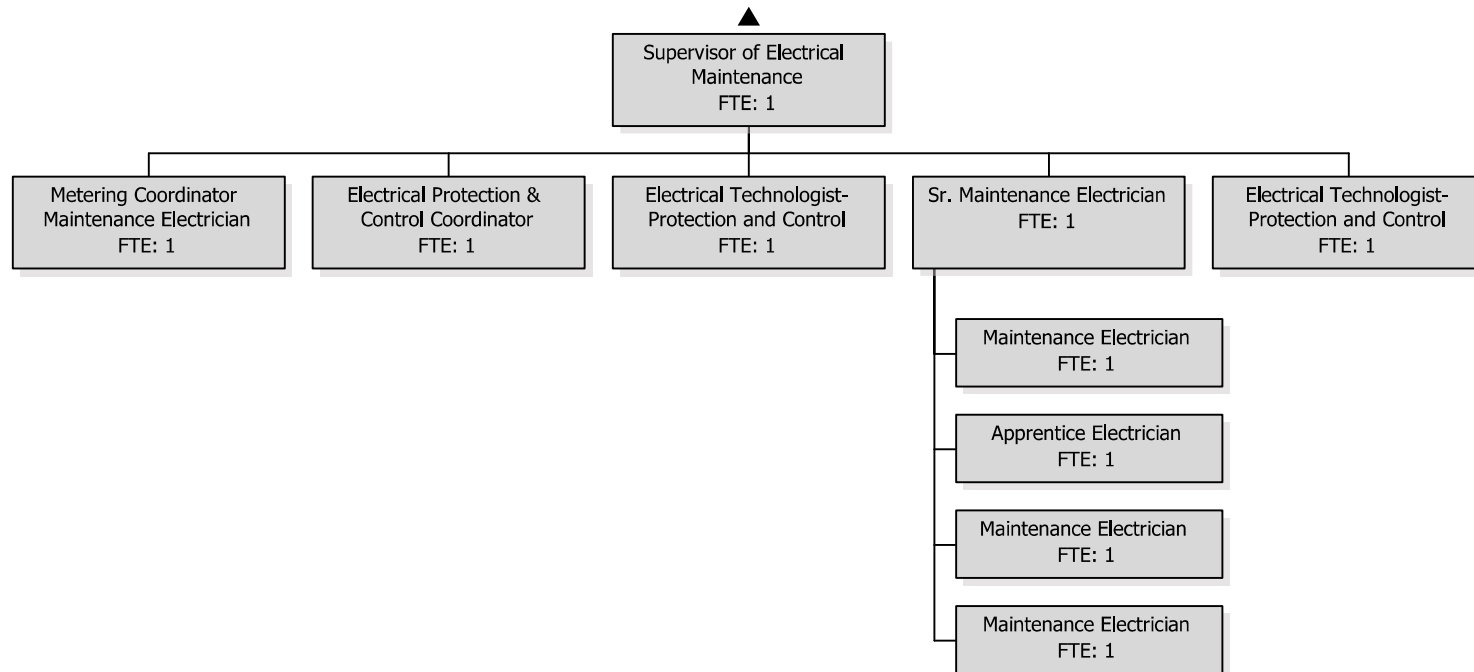
**Figure e14.1.3: Operations, Proposed 2026**

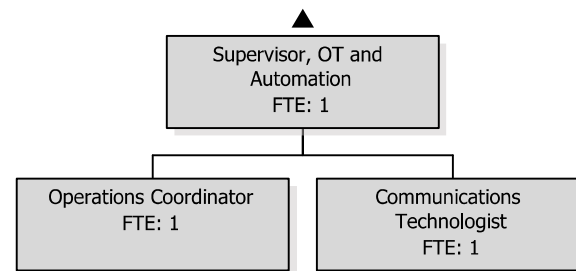
**Figure e14.1.4: Operations, Proposed 2026**



Figure e14.2: Operations, Proposed 2026

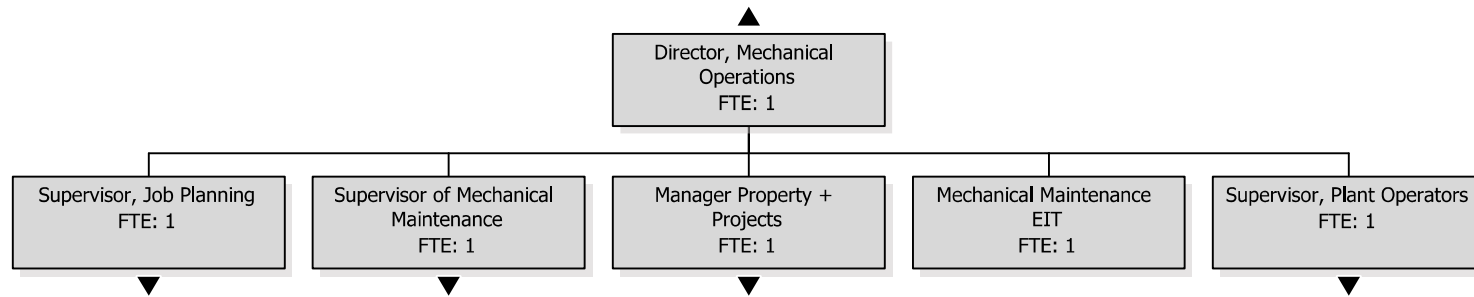


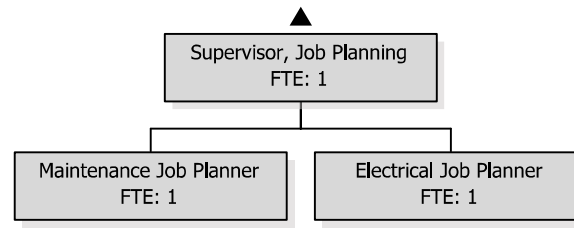
**Figure e14.2.1: Operations, Proposed 2026**



Figure e14.2.2: Operations, Proposed 2026

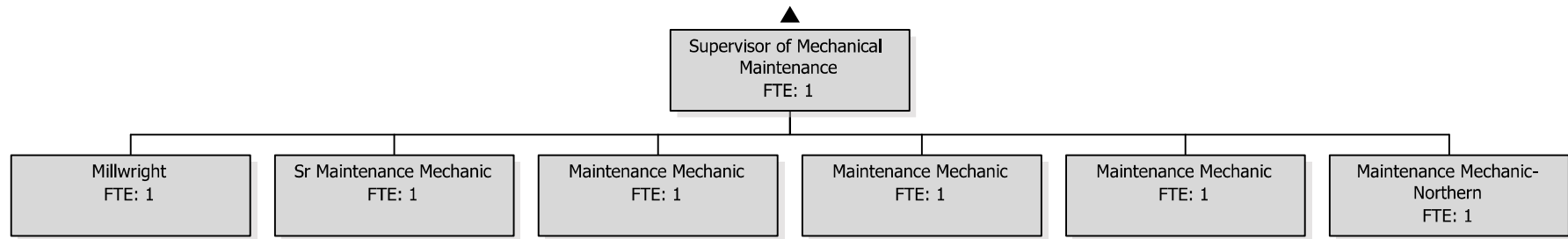




Figure e14.2.3: Operations, Proposed 2026

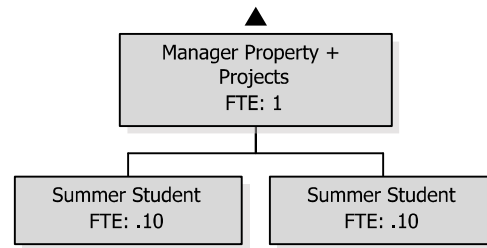


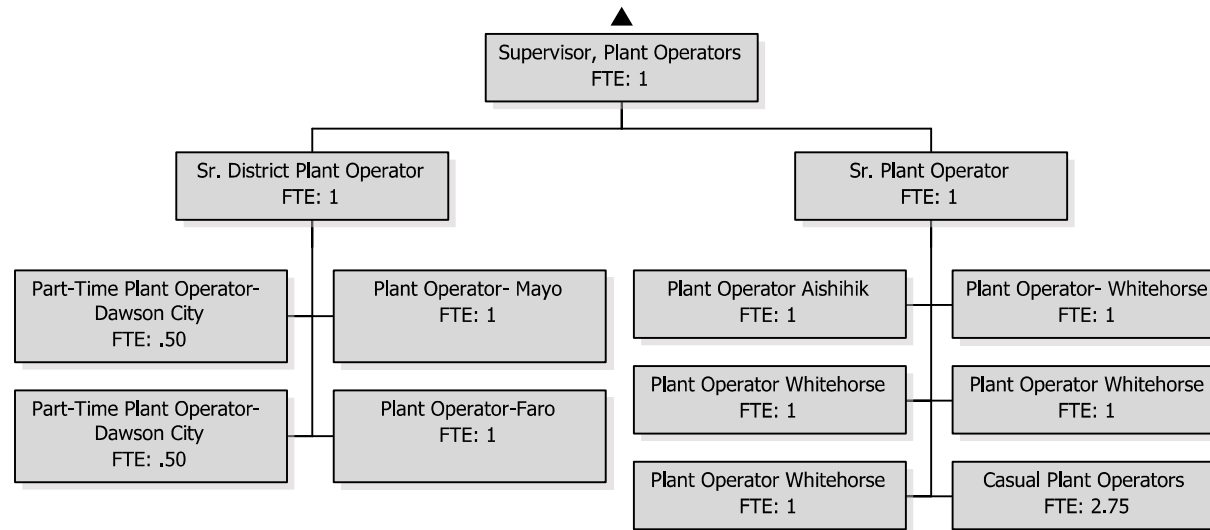
**Figure e14.2.4: Operations, Proposed 2026**

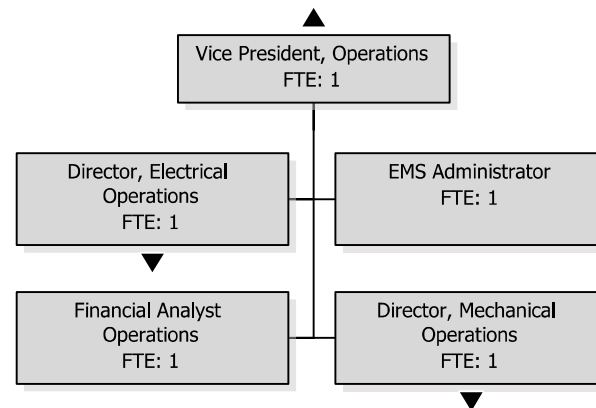
**Figure e15: Operations, Proposed 2027**

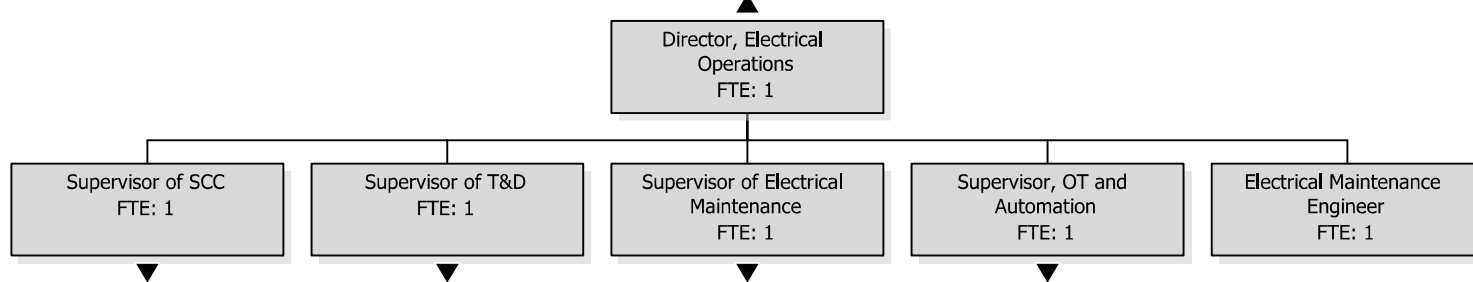
**Figure e15.1: Operations, Proposed 2027**

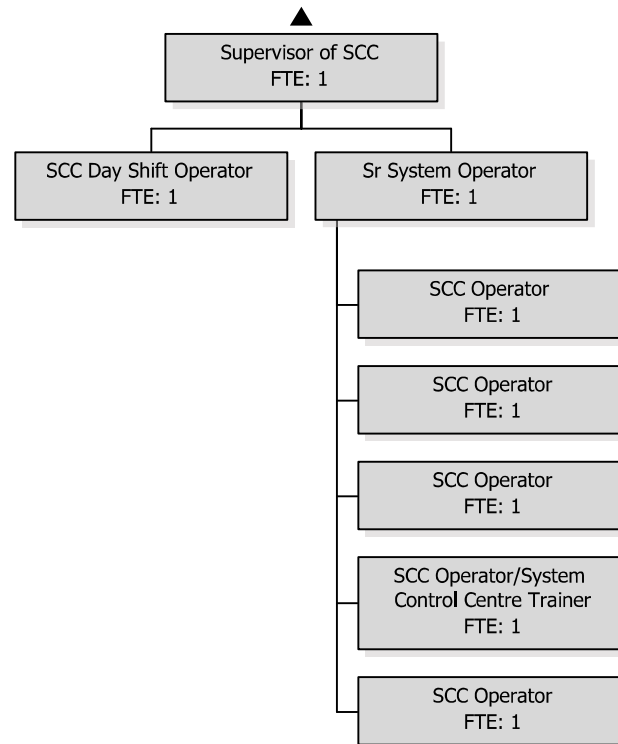
**Figure e15.1.1: Operations, Proposed 2027**



Figure e15.1.2: Operations, Proposed 2027

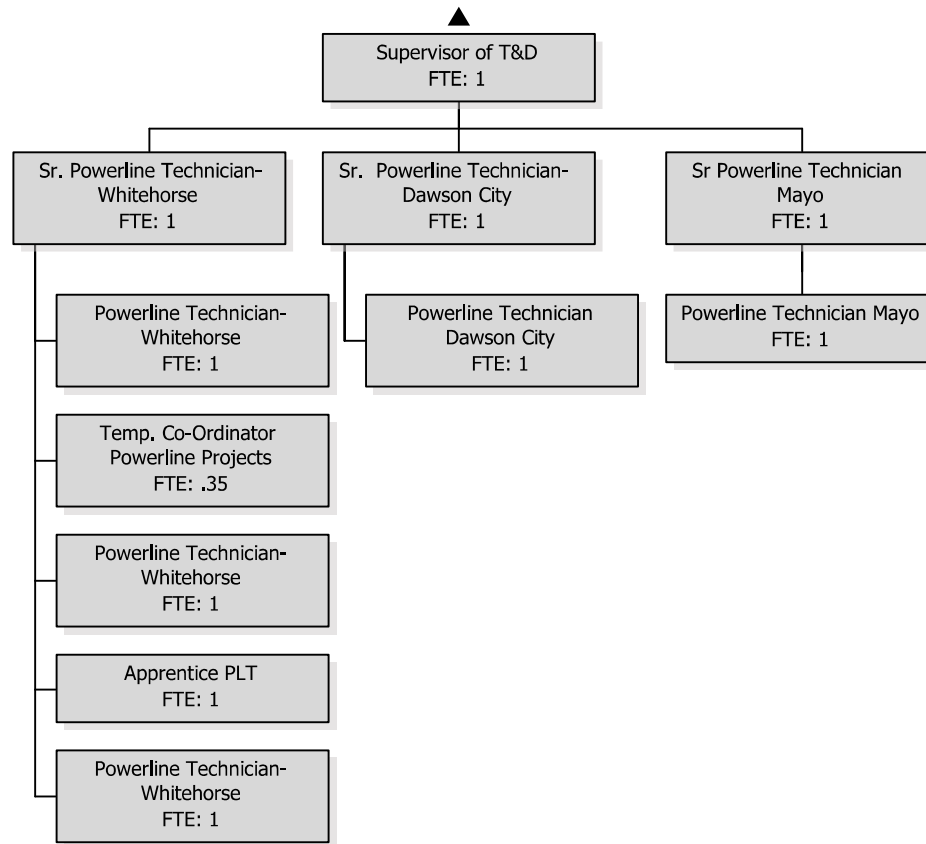


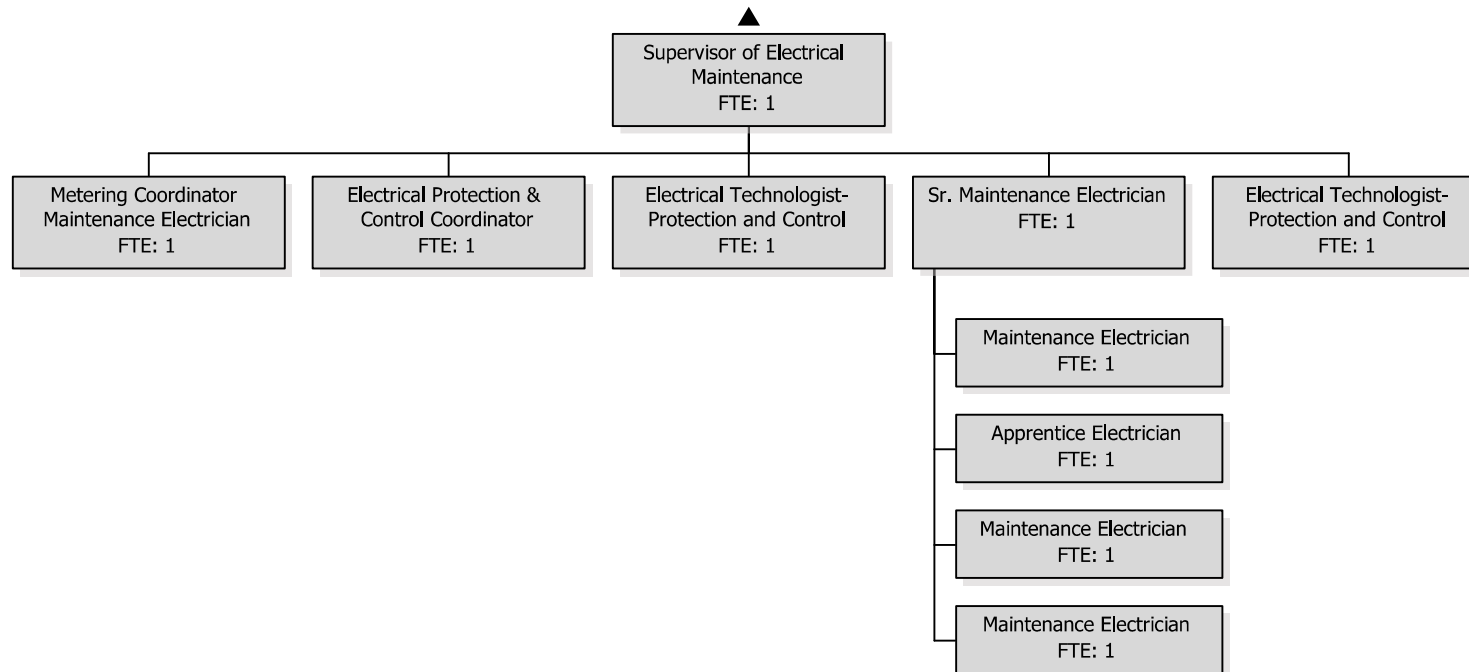
**Figure e15.1.3: Operations, Proposed 2027**



Figure e15.1.4: Operations, Proposed 2027

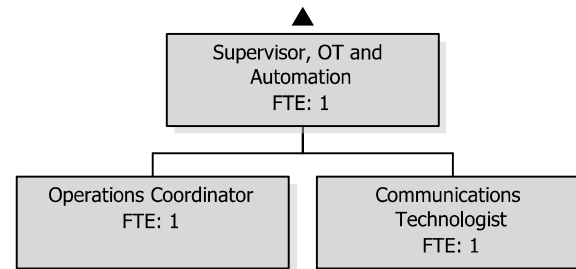


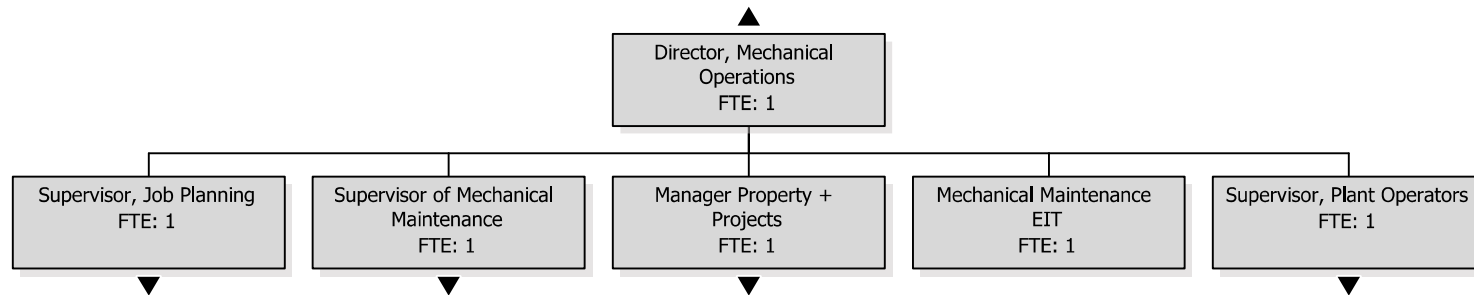
**Figure e15.2: Operations, Proposed 2027**



Figure e15.2.1: Operations, Proposed 2027

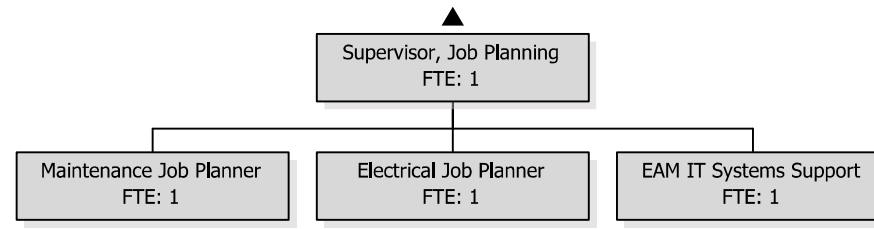




Figure e15.2.2: Operations, Proposed 2027

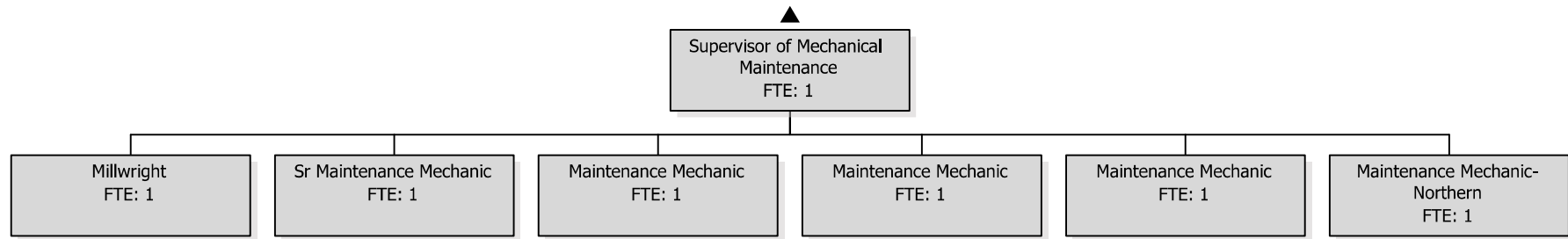




Figure e15.2.3: Operations, Proposed 2027

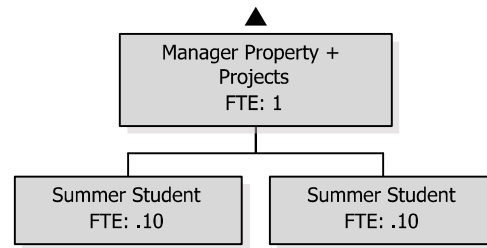
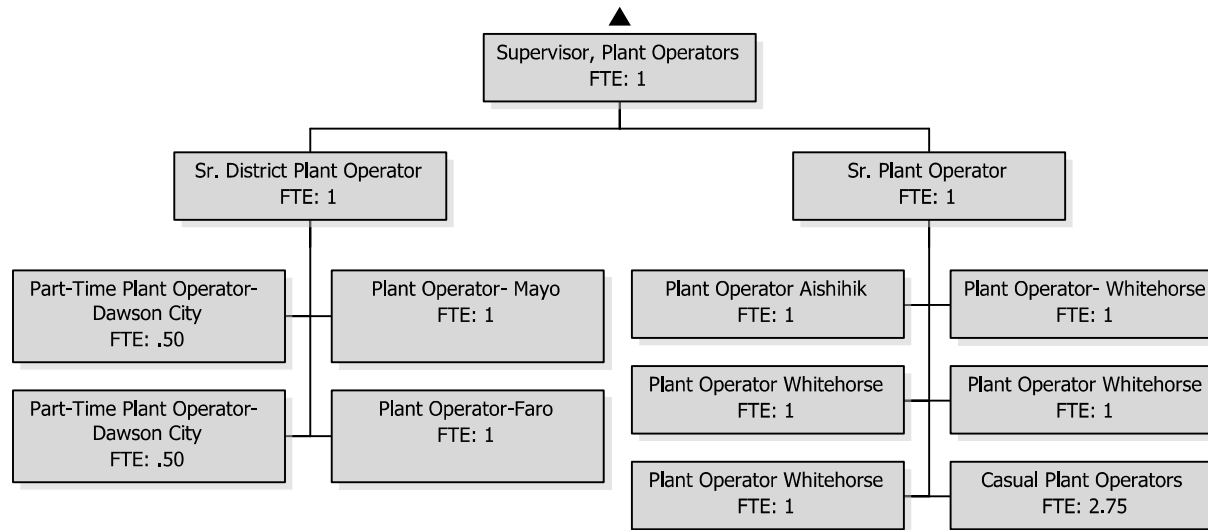


**Figure e15.2.4: Operations, Proposed 2027**

ATTACHMENT 1.6
ENGINEERING SERVICES

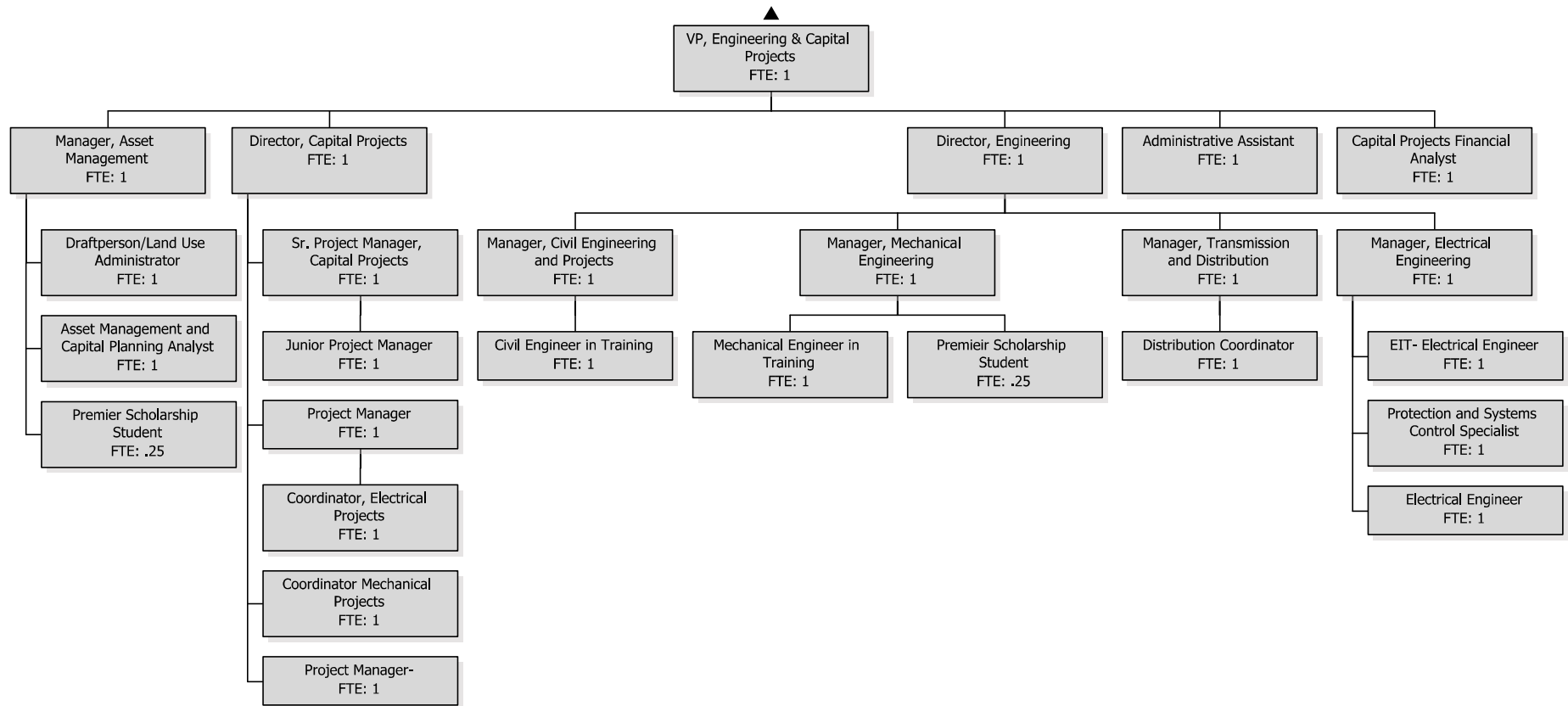
**Figure e16: Engineering Services, Proposed 2025**

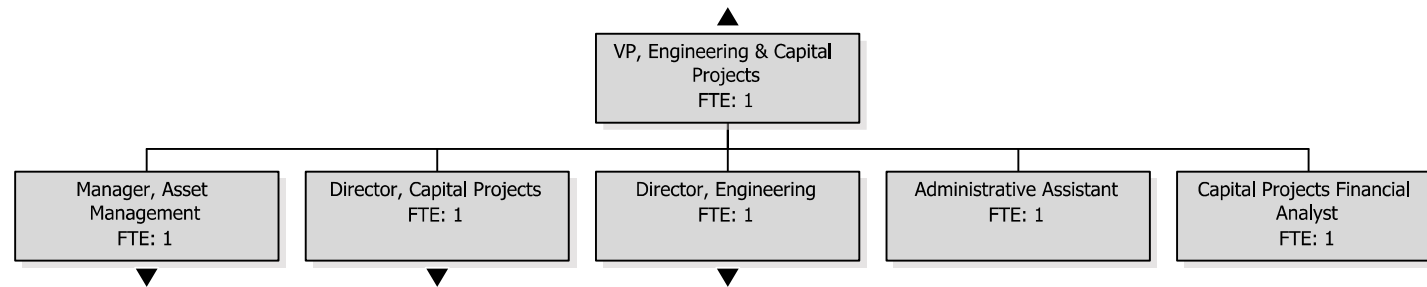
**Figure e17: Engineering Services, Proposed 2025**

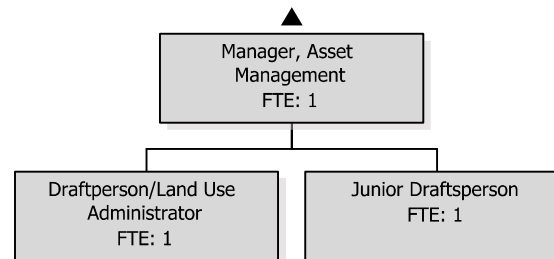
**Figure e17.1 Operations, Proposed 2025**

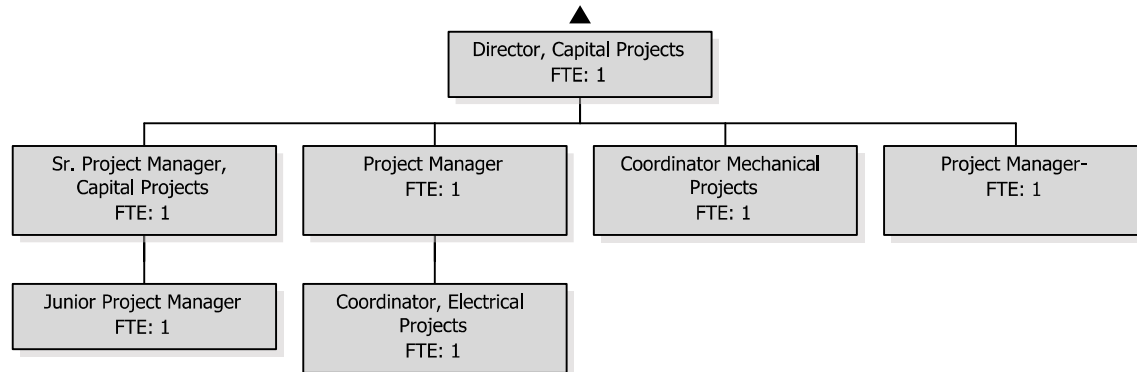
**Figure e17.2: Operations, Proposed 2025**

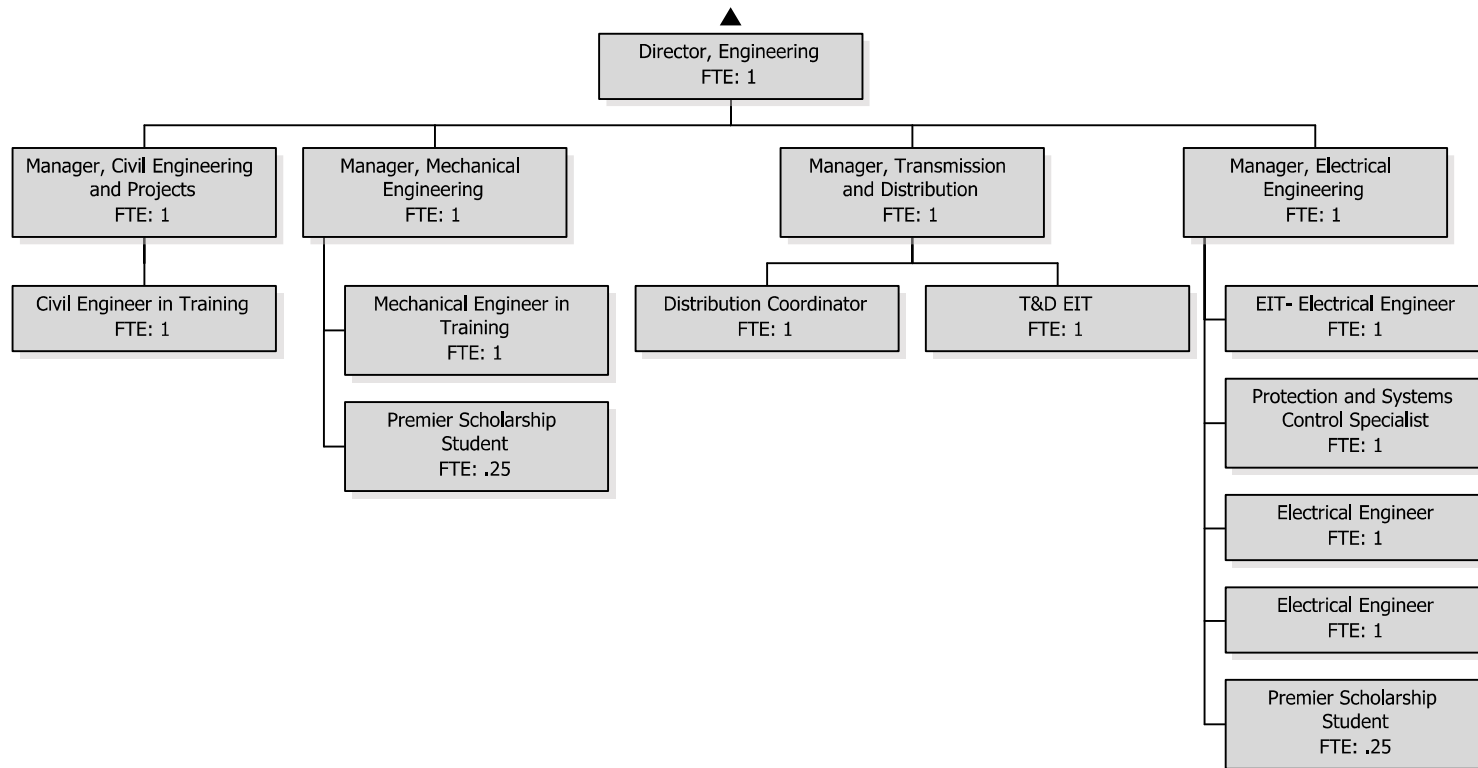
**Figure e17.3: Operations, Proposed 2026**

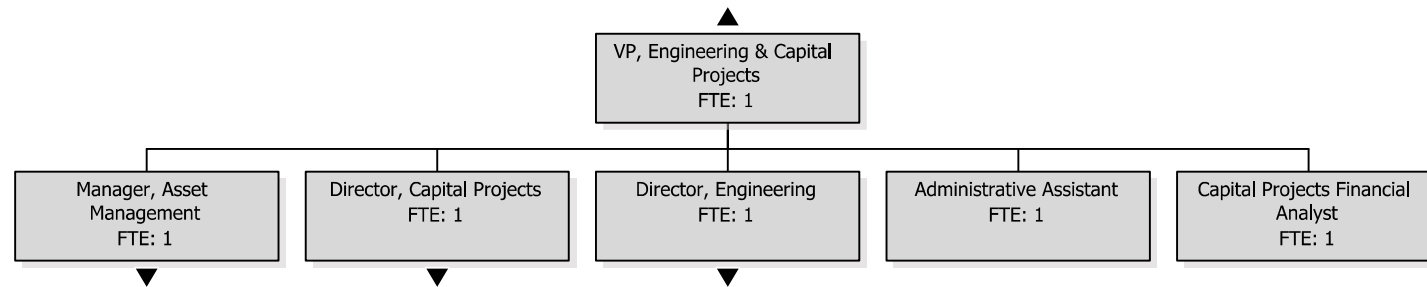
**Figure e18: Operations, Proposed 2026**

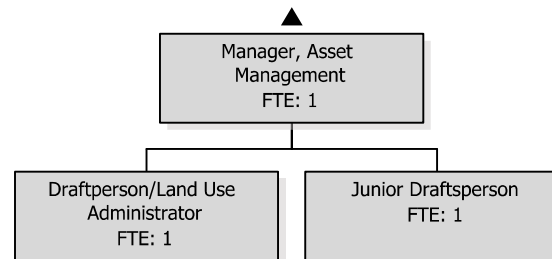
**Figure e18.1: Operations, Proposed 2026**

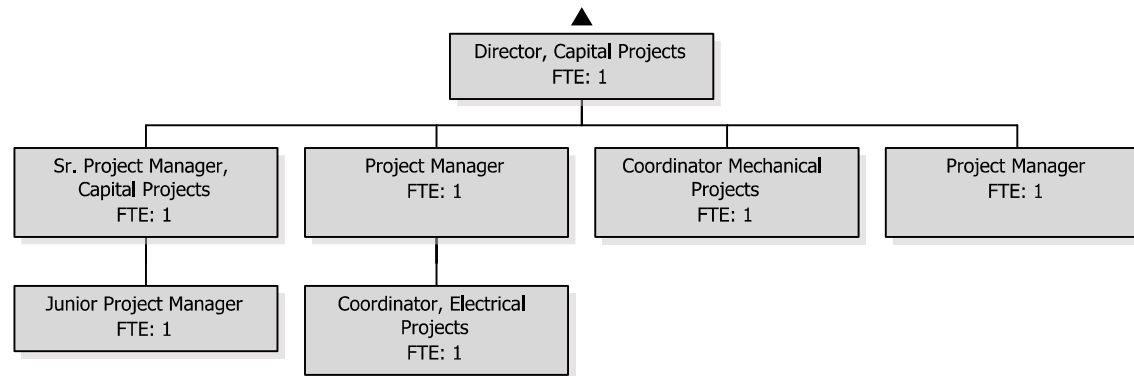
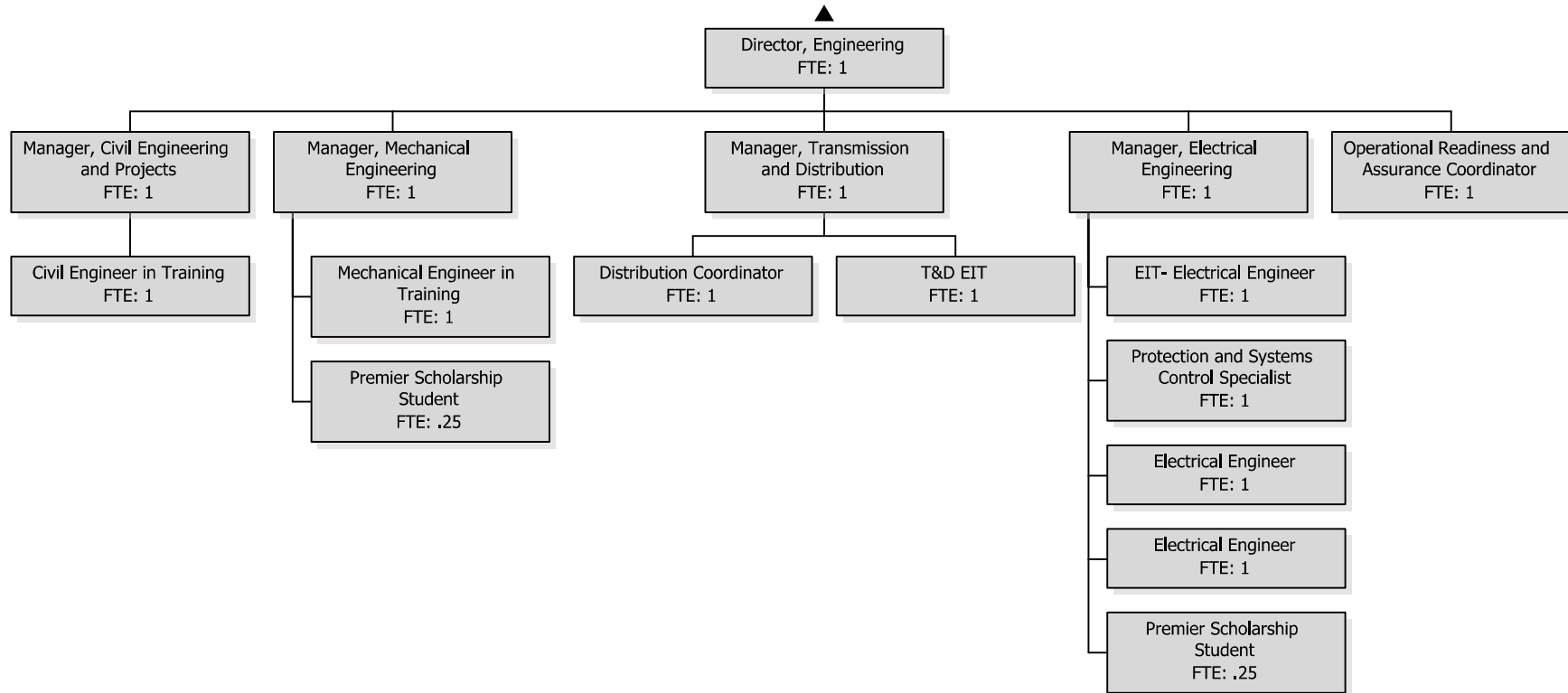
**Figure e18.2: Operations, Proposed 2026**

**Figure e18.3: Operations, Proposed 2026**

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 104, Table 3.15.1

2
3 **ISSUE:** Cost of Debt

4
5 **PREAMBLE:** Table 3.15.1 shows a lender CAFN, and outstanding balance of \$1.0
6 million, and an interest rate of ROE.

7 **QUESTION:**

8
9 a) Please explain the debt from the lender CAFN and whether it arose pursuant to
10 the provisions of the CAFN Final Agreement or any other legislation.

11
12 b) Please describe the repayment terms (return of principle) for that debt.

13
14 c) Please explain why the interest rate is higher than the cost of debt for all other
15 lenders listed in Table 3.15.1.

16
17 d) What direction was YEC given to accept the terms of that debt?

18
19
20 e) When did YEC enter into the debt agreement for the CAFN debt?

21
22 **ANSWER:**

23
24 **(a)**

25
26 The debt from the lender CAFN arose pursuant to a provision in Chapter 22 of the CAFN
27 Final Agreement and that was honoured as part of the AGS Project Agreement signed
28 July 21, 2022.

29
30 **(b)**

31
32 Yukon Energy will repay to CAFN the principal balance at maturity on July 31, 2048.

33
34 **(c)**

35
36 The interest rate on this debt facility was prescribed in the AGS Project Agreement and is
37 equal to the return on equity for Yukon Energy's utility regulatory income for the actual

1 year most recently filed with the YUB under section 25(1) of the Public Utilities Act. The
2 interest rate can be higher or lower than the cost of debt for other lenders listed in Table
3 3.15.1. Yukon Energy's ROE was 3.52% in 2019 and 2.73% in 2020.

4
5 **(d)**

6
7 Yukon Energy was required to accept the terms of the debt to be in compliance with the
8 AGS Project Agreement.

9
10 **(e)**

11
12 Yukon Energy entered into the debt agreement with CAFN on July 21, 2023.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 105

2
3 **ISSUE:** Cost of Debt

4
5 **QUOTE:** As per Board Order 2018-10, the interest rate on new test year debt is
6 determined by a formulaic approach based on the long-term Canada
7 Bonds rate plus 120 basis points (Government of Canada Long-Term
8 Bond Benchmark at 3.35% as of January 28, 2025).
9

10 **QUESTION:**

- 11
12 a) What is the Government of Canada Long-Term Bond Benchmark as of June 30,
13 2025?
14
15 b) What was the Government of Canada Long-Term Bond Benchmark as of January
16 28, 2025 for 2025, 2026 and 2027?
17
18 c) How is the cost of debt from [sic] YDC determined?
19
20 d) How is the cost of debt from TD determined?
21

22 **ANSWER:**

23
24 **(a)**

25
26 The Government of Canada Long-Term Bond Benchmark as of June 30, 2025, was
27 3.56%.
28

29 **(b)**

30
31 The Government of Canada Long-Term Bond Benchmark as of January 28, 2025, was
32 3.35%. There is no separate rate for 2025, 2026 and 2027.
33

34 **(c)**

35
36 The cost of debt from YDC is based on the market rate at the time the agreement is
37 entered into. The market rate was provided by TD Bank, as they were the most recent
38 lender to win the procurement for new debt as they had the lowest rate.

- 1 **(d)**
- 2 Yukon Energy or Yukon Development Corporation request quotes from each of the major
- 3 Canadian banks. TD Bank was selected as they had the lowest rate.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 105

2
3 **ISSUE:** Cost of Debt

4
5 **QUOTE:** During the BESS Part 3 hearing, Yukon Energy proposed that
6 investment opportunity to be provided to the First Nations by structuring
7 the debentures arrangements as a benefit, where Yukon Energy pays
8 the interest on debentures based on the actual rate of return on equity,
9 however, for rate setting purposes Yukon Energy will use the cost of
10 debt to remove impact on ratepayers. The variance between the actual
11 interest rate and interest expense included in the rates will be charged
12 against Yukon Energy's retained earnings. The Board, in its Report
13 dated June 30, 2021, stated that it "accepts YEC's commitment that
14 ratepayers will not be adversely impacted by the debenture investment
15 opportunity." Accordingly, the Application assumes all new debt,
16 including any new debt related to the FN debentures, with an interest
17 rate at 4.55%, which is based on the Bank of Canada benchmark plus
18 120 basis points.

19
20 **PREAMBLE:** The Board seeks further information.

21
22 **QUESTION:**

- 23
24 a) Please provide further explanation of "Accordingly, the Application assumes all
25 new debt, including any new debt related to the FN debentures, with an interest
26 rate at 4.55%, which is based on the Bank of Canada benchmark plus 120 basis
27 points."
28 b) Please explain how the interest rate of 4.55 per cent was derived.

29
30 **ANSWER:**

31
32 **(a)**

33
34 As indicated in the preamble, during the BESS Part 3 hearing, Yukon Energy proposed
35 that investment opportunity to be provided to the First Nations by structuring the
36 debentures arrangements as a benefit, where Yukon Energy pays the interest on
37 debentures based on the actual rate of return on equity, however, for rate setting purposes

1 Yukon Energy will use the cost of debt to remove impact on ratepayers. The variance
2 between the actual interest rate and interest expense included in the rates will be charged
3 against Yukon Energy's retained earnings. The Board, in its Report dated June 30, 2021,
4 stated that it "accepts YEC's commitment that ratepayers will not be adversely impacted
5 by the debenture investment opportunity."
6

7 Based on the forecast rate base for the test years, the Application assumes a new long-
8 term debt of \$72.094 million in 2025, \$81.140 million in 2026 and \$57.684 million in 2027.
9 All these new long-term debt issuances are assumed to have an interest rate of 4.55%,
10 including any new long-term debt required for the BESS project, i.e., for rate making
11 purposes the long-term debt or debentures related to the BESS is assumed at the new
12 long-term debt interest rate rather than the rate of ROE.
13

14 **(b)**
15

16 The interest rate of 4.55% was derived based on Government of Canada benchmark bond
17 yields for Long-Term series at 3.35% on January 28, 2025, plus 120 basis points as
18 directed by the Board.

REFERENCE: YEC 2025-2027 Application, PDF page 99, Table 3.13.1.4

ISSUE: Defined Pension Deferral Account Continuity Schedule

PREAMBLE: The Board seeks further information.

QUESTION:

a) Please explain the additions for 2023 and 2024 for this deferral account.

ANSWER:

(a)

The additions to the deferral account represent the difference between the defined benefit pension cost estimated and included in the labour cost approved in the most recent GRA and the actual defined benefit pension cost determined by the actuary at the end of each year. Details for 2023 and 2024 are below.

(\$ thousands)						
Year	Estimated		Actual		Additions	
2023	\$	255	\$	233	\$	(22)
2024	\$	188	\$	210	\$	22

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 99, Table 3.13.1.5

2
3 **ISSUE:** IPP Purchase Cost Deferral Account Continuity Schedule

4
5 **PREAMBLE:** The Board seeks further information.

6
7 **QUESTION:**

8
9 a) Please explain the additions for 2024 for this deferral account.

10
11 **ANSWER:**

12
13 **(a)**

14
15 The net addition of \$0.041 million in 2024 reflects the following:

- 16
- 17 • Constraint payments to the IPPs for non-permitted outages and curtailments at
18 \$0.058 million.
 - 19
 - 20 • Third party costs [legal fees] related to the IPPs at \$0.009 million.
 - 21
 - 22 • The adjustment of -\$0.026 million to remove the 2024 opening balance [the \$0.026
23 million additions in 2023 were based on the proposed deferral account by Yukon
24 Energy in the 2023/24 GRA, which the Board rejected and approved the deferral
25 account in the base as it was approved for AEY, therefore, the \$0.026 million
26 additions in 2023 are removed in 2024 after the Board order on the 2023/24 GRA].
 - 27
 - 28 • \$0.058 million + \$0.009 million -\$0.026 million = \$0.041 million.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 111

2
3 **ISSUE:** Appendix 3.1 Diesel Rental Business Case

4
5 **QUOTE:** Instead, the plan proposed capital spending on long-term generation
6 and DSM resource options that would continue to be used and useful
7 after Moon Lake pump storage became operational. In that context, it
8 did not appear to be necessary to give specific consideration to other
9 short-term options as an alternative to rental diesel for the period prior
10 to Moon Lake's planned implementation and Yukon Energy's continued
11 reliance on diesel rentals to close the dependable capacity gap.

12
13 **QUESTION:**

- 14
15 a) The above quote appears to say that YEC did not give specific consideration to
16 alternatives to the diesel rentals nor looked beyond the short-term. For most
17 businesses, the short term is considered less than 5 years. What other options can
18 YEC consider instead of diesel rentals to meet its N-1 planning criteria?
19
20 b) It appears YEC was optimistic in terms of the timing for Moon Lake and Atlin. What
21 can YEC do to avoid making such assumptions in the future?
22
23 c) What has YEC learned regarding its diesel rentals and long-term project timelines
24 going forward in order to increase economic efficiency?
25

26 **ANSWER:**

27
28 **(a)**

29
30 Other options Yukon Energy could consider instead of diesel rentals to meet its N-1
31 planning criteria in the short-term include:

- 32
33 • Other sources of supply such as LNG or propane;
34 • Other financing methods such as purchasing;
35 • Demand side management programs; and
36 • Mutual aid programs with AEY, Yukon Government, the City of Whitehorse and
37 Dawson City.

1 Capital spending on alternative supply source options as noted above would not normally
2 be prudent if the asset was expected to be used only for a short-term period.

3
4 **(b)**
5

6 The renewable Moon Lake project was unable to move forward without support from the
7 First Nation whose traditional territory would be impacted. The Atlin Hydro Project is to be
8 developed as an IPP by the local First Nation who owns and operates the existing Atlin
9 hydro site – an EPA between Yukon Energy and the proponent was successfully
10 negotiated, and extensive planning and regulatory work was completed by the project
11 proponent. However, ability to move to construction has been adversely affected by
12 escalated project costs for completion.

13
14 Related lessons from the above include recognition that the following are important factors
15 to the success of any significant new renewable electricity project: meaningful
16 engagement with stakeholders and rightsholders; partnerships with First Nation
17 government(s); access to adequate construction financing and capital; and efficient and
18 coordinated regulatory and permitting processes.

19
20 The 10-Year Plan provided opportunity to develop the two major renewable project options
21 noted here, and in the case of the Atlin Hydro Project in particular a lot of work has been
22 done to try and get this project implemented. Optimism is likely a requirement for
23 undertaking the effort to develop major new renewable project options. In these cases,
24 Yukon Energy net costs on these options was constrained – and the reliance on rental
25 diesels in the meantime has continued to be a cost effective near term option that enabled
26 reconsideration and adjustment of the prior resource plans in light of actual outcomes.

27
28 **(c)**
29

30 Please see response to YUB-YEC-1-8 (a) and (b).

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 112

2
3 **ISSUE:** Appendix 3.1 Diesel Rental Business Case

4
5 **QUOTE:** The Short-Term Actions focusing on 2025-2035, as part of the
6 upcoming Resource Plan, identifies plans to build a reliable and robust
7 grid over the next five years. The goal is to increase the reliability and
8 stability of the grid such that intermittent renewables can be integrated
9 without impacting grid stability as a pathway towards net-zero.

10 ...
11 Renewable energy projects that also provide dependable winter
12 capacity are limited and often face added challenges.

13
14 **QUESTION:**

15
16 a) Please explain how the short-term actions address the issue of diesel rental in this
17 GRA?

18
19 b) Please give an example of a renewable energy project that can provide firm
20 dependable winter capacity within the test years.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Please see the response to YUB-YEC-1-8. The Short-Term Actions undertaken with the
27 Whitehorse Power Expansion Project (now referred to as Whitehorse Power Centres
28 Project will provide permanent thermal capacity in future years to help address the
29 dependable capacity shortfall in future GRAs.

30
31 **(b)**

32
33 There are no projects in this Application which include building a new renewable energy
34 resource (such as pumped storage) that can provide firm dependable winter capacity
35 within the test years. However, the Application includes some projects that provide or
36 maintain the renewable dependable capacity. For example, Mayo projects, including
37 Wareham Dam Spillway Project – Tunnel, MH0 rockslide Stabilization and Remediation

1 and MH0 Surge Chamber Replacement projects are necessary to maintain renewable
2 energy and capacity from Mayo hydro plant. The WRGS, MGS and AGS hydro relicensing
3 projects are also necessary for Yukon Energy to continue to provide the renewable
4 dependable capacity that exists today into the future. The Battery Energy Storage System
5 will also provide dependable capacity, mostly charged by renewable hydro resources.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 113

2
3 **ISSUE:** Appendix 3.1 Diesel Rental Business Case

4
5 **QUOTE:** Amongst other things, Appendix 5.4A provides evidence regarding the
6 timelines expected to be required to develop this new permanent
7 thermal capacity, as directed by the Board in Appendix A of Board
8 Order 2024-05, paragraph 136.

9 ...

10 During the review of its 2021 GRA, Yukon Energy explained why
11 trading diesel engines [i.e., purchasing diesel rental units and sale later
12 when it is not needed] is not considered to be a feasible option for
13 Yukon Energy. This was iterated in the 2023/24 GRA, and it remains
14 the case for this GRA. However, Yukon Energy is exploring options to
15 purchase a small number of units to use them as mobile units to support
16 the system.

17 [YEC has edited the quote above to correspond to the PDF page 113.]

18
19 **QUESTION:**

- 20
21 a) What has YEC done differently to increase the accuracy of the timelines referred
22 to in Appendix 5.4A?
23
24 b) Please explain why, in the second quote above, YEC only focused on purchasing
25 diesel rentals instead of other diesel units? Does focusing only on diesel rental
26 units impair the accuracy of YEC's analysis? Please explain.
27
28 c) Has YEC commented on the performance of the diesel units in the past (less
29 reliable, higher forced outage rate, requirement of spare units in excess of the
30 quantity need to meet the N-1 criteria)? If this is affirmative, why would YEC
31 consider purchasing a small number of units as mobile units?

1 **ANSWER:**

2
3 **(a)**

4
5 Yukon Energy has taken several actions to mitigate potential delays in the timelines for
6 the Whitehorse Power Expansion Project (now referred to as the Whitehorse Power
7 Centres Project), referred to in Appendix 5.4A and updated in YUB-YEC-1-08 including:

8
9 • **Managing permitting timeline:**

- 10
11 o Initiated the Executive Committee Screening process with the Yukon
12 Environmental and Socio-economic Assessment Board (YESAB) more
13 than two years before the anticipated in-service date of winter 2027;
14 and
15
16 o Yukon Energy has submitted a request to YESAB on August 5th, 2025,
17 to shorten prescribed review timelines during the permitting process.

- 18
19 • **Collaborating with local First Nations:** Yukon Energy held multiple meetings
20 with the two Yukon First Nations in the project area, Kwanlin Dün First Nation
21 and Ta'an Kwäch'än Council, to introduce the project and communicate the
22 need for dependable winter capacity in the Yukon, as well as discuss possible
23 site locations for the facilities. Both Nations provided Settlement land options
24 for consideration for the Whitehorse Power Expansion Project.

- 25
26 • **Supporting internal resources:** Given the size and scope of the project,
27 Yukon Energy has developed a multi-disciplinary team, with the support of
28 external project managers and subject matter experts.

29
30 Since the 2021 GRA, permanent solutions for renewable sources of winter dependable
31 capacity have been delayed as identified in YUB-YEC-1-8. In addition to changes made
32 to the effective load carrying capability of existing resources consistent with industry best
33 practices, Yukon Energy has also updated the short-term and long-term load forecast. As
34 new information becomes available, Yukon Energy updates the resource options and
35 proceeds with the best option to provide reliable power to rate payers.

1 **(b)**

2
3 Yukon Energy is focusing on purchasing diesel and/or LNG units to meet the urgent
4 demands for winter power but has noted the timelines needed for this. Yukon Energy has
5 also explored the option of purchasing mobile units from the Eagle Gold or Minto mine
6 sites.

7
8 Yukon Energy has continually assessed the need to build a permanent solution as
9 described in response to YUB-YEC-1-8. Until a new thermal site is in-service, the cost-
10 effective stop gap solution has been rental diesel units, as identified in the diesel rental
11 business case.

12
13 **(c)**

14
15 The reliability and forced outage rates of all thermal assets have historically been
16 considered in Yukon Energy's capacity planning criteria. We identified performance issues
17 with the rental diesel units in recent winters, and we are actively working to mitigate these
18 issues such as (1) starting units in advance of very cold-weather, (2) increased staffing to
19 respond more quickly to unplanned outages, and (3) setting up alarms in SCADA to
20 improve visibility and tracking of unit issues.

21
22 The diesel rentals are owned and maintained by Finning, meaning performance and
23 maintenance issues were not tracked like Yukon Energy units, but Yukon Energy has
24 recently started tracking unit availability via SCADA and manually tracking issues
25 encountered this past winter. Purchased mobile units would not have the same issues
26 faced with rental diesel units and the performance of purchased mobile units would be
27 more comparable to YEC owned units.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 115 and footnote 5

2
3 **ISSUE:** Appendix 3.1 Diesel Rental Business Case

4
5 **QUOTE:** PDF page 115:

6 The LCOC over a 40-year life for the 16.5 MW Thermal Replacement
7 Project at \$228.8 per kW-yr (2025\$) compares to the LCOC of \$207.6
8 per kW-yr for 2025 rental diesel cost for all diesel rental units with
9 2%/year increase in diesel rental cost, and LCOC of \$239.6-\$279.4 per
10 kW-yr with 3%-4%/year increase in diesel rental cost (assuming a 40-
11 year life and excluding rental capital infrastructure costs).

12 Footnote 5:

13 LCOC assessed assuming total rental cost of \$6.9 million for 22 units
14 to total of about 34 MW [with 15% Forced Outage Rates (FOR)]. The
15 rental cost is assumed to increase 2%/year, sensitivity cases are
16 included for 3% and 4%/year rental cost increases. The LCOC for the
17 16.5 MW thermal replacement project is based on the total cost of \$62.2
18 million. Yukon Energy WACC for new rate base of 6.390%/year per
19 2025-27 GRA (60% new debt financed at 4.55% and 40% equity
20 financed at 9.15% per the current Application). This comparative cost
21 analysis does address net benefits from new, more environmentally
22 friendly, likely lower operating cost Tier 4 new permanent diesel units
23 compared to the Tier 2 rental units (Appendix A to Board Order 2024-
24 05, paragraph 135, noted this limitation to this analysis).

25 **QUESTION:**

26
27 a) Please explain the reasonableness of the analysis of comparing Tier 2 rental units
28 to Tier 4 permanent diesels.

29
30 b) Please redo the analysis referred to above comparing Tier 2 rentals to Tier 2
31 permanent diesels.

32
33 **ANSWER:**

34
35 **(a) and (b)**

36
37 While the LCOC for Tier 2 and Tier 4 units may not provide a head-to-head comparison,
38 the analysis is reasonable as it compares the diesel options relevant to Yukon Energy

1 during recent decision periods, i.e., permanent Yukon Energy-owned Tier 4 units versus
2 the available rental Tier 2 units. Although the rental gensets do not comply with the US
3 EPA Tier 4 standards, Tier 2 is permissible in many regions for temporary or mobile diesel
4 gensets and there is an exemption for remote/islanded communities such as the Yukon
5 electrical grid.

6
7 Yukon Energy does not have information about the cost impact of renting Tier 4 diesel
8 units instead of Tier 2 diesel units. However, as indicated in response to YUB-YEC-1-37
9 (f) during the 2023/24 GRA process, the exact price difference per MW between Tier 2
10 and 4 permanent units will vary based on specific models and manufacturers. As indicated
11 in the same response, based on quotes received by Yukon Energy at the time, the quoted
12 price for installing 12.5 MW of Tier 4 units was about \$3 million greater than for Tier 2
13 units.

14
15 For the purpose of this IR response, Yukon Energy assumes that the price impact for the
16 16.5 MW Thermal Replacement Project would be around \$4 million based on the \$3 million
17 impact for 12.5 MW [$\$3\text{M} \times 16.5/12.5$]. This is about 6% of the total cost of the 16.5 MW
18 Thermal Replacement Project, which would reduce the calculated LCOC to about \$215
19 per kW-yr compared to the LCOC estimate of \$229 per kW-yr for Tier 4.

20
21 In summary:

- 22
- 23 • Whether assuming Tier 2 or Tier 4 new diesel units, the LCOC for the new Yukon
24 Energy owned units based on the 16.5 MW Thermal Project cost is higher than the
25 LCOC for renting Tier 2 diesel units with 2%/year increase in diesel rental cost;
26 however, the LCOC for the new Yukon Energy owned units is lower than the LCOC
27 for renting Tier 2 diesel units if the annual increase in the diesel rental cost is 3%
28 or 4% per year.
 - 29
 - 30 • The diesel rental costs may increase at higher than inflation rates; however, even
31 with a cost increase of 3% to 4% per year, the rentals are in a range comparable
32 to permanent diesel units.
 - 33
 - 34 • Although the analysis shows that the cost of the diesel rentals is reasonable as a
35 short-term option, Yukon Energy is constantly working towards a permanent
36 solution as explained in the response to YUB-YEC-1-8.

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 148

2
3 **ISSUE:** Thermal Fuel Mix

4
5 **QUOTE:** Yukon Energy does not have enough evidence at this time to support
6 a change in the LTA blended fuel mix ratio to a 70%/30% mix based on
7 actual results considering the percentages were impacted by the wide
8 range of factors noted. There are also impacts from lower LNG
9 percentages as noted below. Therefore, Yukon Energy is proposing to
10 use an 80% LNG and 20% diesel mix for the fuel cost calculations for
11 the 2025, 2026, and 2027 test years (which is the average between
12 90/10 and 70/30 based on actuals for the previous years).

13
14 Use of a lower allocation of LNG would lead to higher fuel costs. The
15 table below shows the impact of the change in the fuel mix on the
16 revenue requirement for 2025. While this will lead to higher fuel costs
17 compared to the 90/10 mix, the impact will be lower than the 70/30 mix
18 based on actuals as shown in the table below.

19 **QUESTION:**

20
21 a) Please explain the impact of the above and how it relates to Rider F.

22
23 b) With Rider F, is it a correct assumption that no matter what the forecast fuel cost
24 is or the forecast fuel mix, customers will only pay the actual fuel costs (based on
25 LTA)? Please explain.

26
27 **ANSWER:**

28
29 **(a)**

30
31 Please see the response to YUB-YEC-1-28 (a) and (b) for the impacts of the fuel mix.
32 Rider F deals with the variances in the fuel prices and efficiencies based on actual fuel
33 used, regardless of the approved fuel mix. Therefore, there is no impact to Rider F from
34 the proposed fuel mix.

1 **(b)**

2

3 Confirmed, subject to caveat noted below. Rider F deals with the variance between
4 approved fuel prices/efficiencies and actual fuel prices/efficiencies based on actual fuel
5 volume used, regardless the forecast fuel mix or fuel cost. However, it should be clarified
6 that the actual fuel cost is not based on the LTA, but rather the actual fuel used. The LTA
7 related variances are dealt with under LWRF in accordance with the approved LWRF
8 Term Sheet.

REFERENCE: YEC 2025-2027 Application, Appendix 3.4 Vegetation Management Plan, PDF pages 149-165

ISSUE: Vegetation Management Plan

QUOTE:

Table 4: 2024 O&M Work Forecast

PROJECT	TRIM	SLASH	MOW ¹	TOTAL	O&M MECHANICAL WORK
Line Number	M ²	M ²	M ²	M ²	\$
L171	0	5,537	6,471	12,008	21,004
L170	2,790	122,301	135,838	260,929	474,087
L178	32	48,535	57,315	105,882	184,801
L173	0	22,588	241,154	263,742	268,227
L172	0	10,220	0	10,220	28,616
L169	0	1,192	0	1,192	3,338
L355	0	73	60,589	60,662	51,705
L254	0	183	0	183	512
L177	217	25,858	255,793	281,868	291,085
L174	705	7,700	17,390	25,795	40,431
L176	0	0	40,619	40,619	34,526
L180	0	0	0	0	0
L175	0	0	0	0	0
L356	120	68,977	171,860	240,957	339,913
L250	0	2,080	5,599	7,679	10,583
L453	707	1,179	0	1,886	7,402
Total	4,571	316,423	992,628	629,895	1,756,230

Table 5: 2024 Capital Work Forecast

PROJECT	HAZARD TREE	HAZARD TREE	DANGER TREE	DANGER TREE	MECHANICAL WIDENING	MECHANICAL WIDENING
Line Number	# of Trees	\$	# of Trees	\$	M ²	\$
L171	22	3,630	386	63,690	271,400	949,900
L170	97	16,005	506	83,490	0	0
L178	476	78,540	489	80,685	0	0
L173	40	6,600	1,174	193,710	0	0
L172	14	2,310	474	78,210	0	0
L169	0	0	5	825	0	0
L355	76	12,540	0	0	0	0
L254	16	2,640	32	5,280	0	0
L177	85	14,025	0	0	0	0
L174	157	25,905	602	99,330	0	0
L176	26	4,290	0	0	0	0
L180	64	10,560	83	13,695	0	0
L175	80	13,200	0	0	0	0
L356	12	1,980	0	0	0	0
L250	9	1,485	52	8,580	0	0
L453	54	8,910	0	0	0	0
Total	1,228	202,620	3,803	627,495	271,400	949,900

PREAMBLE: Appendix 3.4 provided a Vegetation Management Plan respecting a “10-Year Plan to Manage Vegetation along Yukon Energy Corporation Rights of Way.” The Board would like to understand how successful YEC has been in achieving the objectives set out in this report for the year 2024.

QUESTION:

- a) Referring to Appendix 3.4, Table 4 - 2024 O&M Work Forecast and Table 5 - 2024 Capital Work Forecast, please provide a table with details comparing the work forecast for that year with what was accomplished on an actual basis along with explanations for any variances noted between the two.

b) Separately, please correlate the information provided in part (a) for O&M work and provide quantum and unit cost details respecting 2024 forecast and actual costs for both distribution and transmission functions that would correspond to Tab 3 tables, Table 3.6.1 Brushing Costs.

ANSWER:

(a)

A table comparing the work as detailed in ATCO's Vegetation Management Plan as compared to actual work accomplished in 2024 is provided below.

2024 O&M Work

Atco Vegetation Management Plan		Actual	Difference
Line Number	\$ thousands	\$ thousands	
L171	\$ 21	\$ 57	\$ 36
L170	\$ 474	\$ 485	\$ 11
L178	\$ 185	\$ 4	\$ (180)
L173	\$ 268	\$ 238	\$ (30)
L172	\$ 29	\$ -	\$ (29)
L169	\$ 3	\$ -	\$ (3)
L355	\$ 52	\$ -	\$ (52)
L254	\$ 1	\$ -	\$ (1)
L177	\$ 291	\$ 29	\$ (262)
L174	\$ 40	\$ 128	\$ 87
L176	\$ 35	\$ -	\$ (35)
L180	\$ -	\$ -	\$ -
L175	\$ -	\$ -	\$ -
L356	\$ 340	\$ 33	\$ (307)
L250	\$ 11	\$ -	\$ (11)
L453	\$ 7	\$ -	\$ (7)
Substations	\$ -	\$ 27	\$ 27
Total	\$ 1,756	\$ 1,001	\$ (755)

There are variances between total work accomplished in 2024 and activities as recommended in the Vegetation Management Plan provided by ATCO for various reasons. First, as the report was not finalized until October 7, 2024, Yukon Energy had

already performed much of its annual brushing. Second, Yukon Energy did not have sufficient budget available to spend the full amount as recommended by ATCO. The 2024 Approved Total Brushing Expense was only \$1.339 million as compared to the ATCO recommendation of \$1.756 million. In addition, there was no 2024 Approved spending for Capital Brushing. Furthermore, as per Board Order 2024-05, Yukon Energy was ordered to expense the Vegetation Management Plan, at a cost of \$223,000, which also resulted in less funds being available for O&M. In summary, total 2024 Brushing expense was \$72,000 less than 2024 Approved.

Brushing O&M	\$	1,001
Brushing Admin		43
Vegetation Management Plan		223
Total 2024 Actual Brushing	\$	<u>1,267</u>
Total 2024 Approved Brushing	\$	<u>1,339</u>
Difference	\$	(72)

Regarding specific line work in 2024, while Yukon Energy uses ATCO's report as a guide, final decisions on work are based on vegetation conditions at the time, opportunities to realize cost efficiencies, current wildfire conditions, etc. ATCO's report goes span by span and does not take into account the time it takes to travel from span to span. This can lead to identification of many little sections of line to brush at a time, which can lead to inefficiencies. Instead, Yukon Energy groups larger sections of transmission lines together so the crews spend more time brushing and less time travelling from section to section. In addition, Yukon Energy considers terrain variability when assigning brushing work; this was not captured in the ATCO report.

Considering the above, the work identified by Yukon Energy as the highest priority was completed in 2024. The Yukon Energy brushing coordinator identified long-term efficiencies by grouping larger sections of brushing together, which accounts for the cost variances in some individual lines (L171 and L174). L356 was identified in Yukon Energy's plan for 2024 but the ground conditions did not allow this line to be worked on in 2024. This section needs to be brushed in winter and the ground did not freeze early enough. L177 was partially completed by highway widening work rather than by Yukon Energy workers.

While the question only asked about brushing information regarding 2024, significant deviations from the Application have also developed in 2025 and are also expected to impact 2026 brushing maintenance expenses. In Yukon Energy's Application, forecasts for 2025 through 2027 were based on the ATCO Vegetation Management Plan. Due to unexpected complexities arising during the procurement of 2025 transmission brushing activities, the procurement of transmission brushing was cancelled at the end of the process, and will be redone later in 2025. As a result, a significant amount of brushing maintenance that was expected to occur in 2025 has been reallocated to 2026 (in addition to the work already planned for 2026).

Yukon Energy's forecast brushing cost included in the Application was based on the best information available at the time. However, as Yukon Energy has revised its 2025 and 2026 plans, brushing costs for 2025 and 2026 are now forecast to be significantly different than submitted in the Application. The below compares the updated forecasts to the Application.

(\$000's)	2025	2026	2027
Updated Forecast	\$ 937	\$ 2,156	\$ 1,255
Application Forecast	\$ 1,398	\$ 1,695	\$ 1,255
Difference	\$ (461)	\$ 461	\$ -

(b)

A correlation of the information provided in part (a) for O&M work respecting 2024 costs for both distribution and transmission functions that corresponds to Tab 3 tables, Table 3.6.1 Brushing Costs is below.

	Approved 2024	Preliminary Actual 2024	Final Actual 2024
Brushing O&M (correlation to part a)			
Transmission Brushing O&M			
L171		\$	57
L170			485
L178			4
L173			238
L177			29
L174			128
L356			33
Substations			26
Transmission Brushing O&M		\$	999
Distribution Brushing O&M			
Substations		\$	2
Distribution Brushing O&M		\$	2
Total Brushing O&M (correlation to part a)		\$	1,001
Brushing Admin			
Transmission Brushing Admin		\$	43
Distribution Brushing Admin			-
Vegetation Management Plan			223
Total Brushing Admin		\$	266
Correlation to Table 3.6.1			
Transmission Brushing	\$ 1,131	\$ 1,305	\$ 1,043
Distribution Brushing	208	280	2
Vegetation Management Plan	-	-	223
Total Brushing Expense	\$ 1,339	\$ 1,585	\$ 1,267

1

REFERENCE: YEC 2025-2027 Application, Appendix 5.3, FX-001 Criteria for Capitalization, PDF pages 431-438; Tab 3 tables 2025-27 GRA, Table 3.13

ISSUE: FX-001 Criteria for Capitalization

QUOTE: 1.0 Purpose
 To provide guidelines for determining whether expenditures should be capitalized or expensed. Primary source used is IAS 16 Property Plant and Equipment and industry guidance (BC Hydro).

...

3.0 Criteria for Capitalization Notwithstanding clause 2.0, expenditures are considered capital in nature if one or more of the following criteria are met: a) If they have been incurred to acquire, construct, or develop assets that will be used on a continuing basis for longer than one year. b) The resulting asset will be held for use in the generation, transmission, or distribution of electricity, directly or indirectly. c) The cost is significant relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed \$1,000.

...

4.1 Subsequent Costs Replacement of Existing Assets Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, the headgate of a dam may require replacement. Under the recognition principle, an entity recognizes in the carrying amount of an item of property, plant, and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria in 2.0 are met. The carrying amount of those parts that are replaced is derecognised (ref: IAS 16, para 13).

...

Acquisition Costs for capitalization include, but are not limited to:

...

s. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period. (IAS 16, para 16(c))

...

1 The Corporation capitalizes streetlights, regardless of the cost of each
2 streetlight. The Corporation capitalizes transformers and breakers,
3 regardless of the cost of each transformer and breaker.

4 ...

5 11.0 Depreciation

6 Assets are depreciated based on the estimated useful life of the
7 assigned asset class as per the 'GP Users Manual for Property Plant
8 and Equipment'. Estimated useful lives are re-evaluated as required via
9 a third-party depreciation study.

10
11 **QUESTION:**

- 12
- 13 a) Please provide a copy of IAS 16 Property Plant and Equipment.
- 14
- 15 b) As proposed in FX-001 Criteria for Capitalization, has YEC's \$1,000 threshold for
16 capitalization changed from some other amount? If so, please explain.
- 17
- 18 c) Please provide the dollar value thresholds for capitalization for utilities that YEC
19 considers to be peer utilities.
- 20
- 21 d) Please explain what is meant by the phrase noted in the quoted passage above
22 that indicates that the carrying amount of an asset that is replaced is
23 "derecognized." In your response, please explain how this is different from retiring
24 an asset, or removing an asset from utility service if it is no longer used or useful?
25 Please provide an example of a typical accounting entry for a "derecognized" asset
26 transaction.
- 27
- 28 e) Does part (s) as quoted above assume Board approval of YEC's proposed
29 changes to its net salvage methodology? Please explain.
- 30
- 31 f) If the response to part (e) above is negative and given that part (s) as quoted above
32 indicates that the acquisition cost includes "the initial estimate of the costs of
33 dismantling and removing the item and restoring the site on which it is located,"
34 how does this accord with YEC's treatment of net salvage costs under the existing
35 Board approved future removal and site restoration (FRSR) practice which does
36 not currently allow for the pre-collection of net salvage costs in revenue
37 requirement?

- 1 g) Please explain the basis for the of the capitalization of streetlights, transformers,
2 and breakers regardless of their respective costs.
3
- 4 h) Are Major overhauls as referred to in subsection 4.2
5 Overhauls/Inspections/Certification; 4.2(a) Diesel Units; 4.2(b) Hydro Units; 4.2(c)
6 Gas Units required to meet the \$1,000 threshold for capitalization?
7
- 8 i) Please explain how the \$1,000 threshold applies to subsections 5.0 Intangible
9 Assets; 6.0 Regulatory and Licensing Projects; 7.0 Capital Leases (Right-of-Use-
10 Assets) and 8.0 Critical Spares.
11
- 12 j) At what point during an asset's physical construction is the asset capitalized into
13 YEC rate base? Are there, or have there been, any instances where a completed
14 portion of a capital project was capitalized prior to the completion of an entire
15 capital project? If so, please explain the circumstances.
16
- 17 k) Please point to where the policy related to asset recognition as discussed in part
18 (j) has been articulated in FX-001 Criteria for Capitalization or any other of YEC's
19 capital related policies or similar.
20
21
- 22 l) Please clarify YEC's policy and procedure with respect to asset recognition as it
23 pertains to each of rate base, mid-year rate base, the calculation of AFUDC and
24 the calculation of return on mid-year rate base. Please identify a policy where each
25 of these accounting and regulatory practices are articulated.
26
- 27 m) Please clarify YEC's policy and procedure for commencing depreciation expense
28 for a newly capitalized utility asset, explaining the point at which depreciation
29 commences for each of financial accounting and regulatory accounting purposes.
30 Please provide an example depreciation expense calculation for an asset costing
31 \$2,000 placed into service on February 15, 2025, with an average service life of
32 15 years under each of a financial accounting and regulatory accounting scenario.
33
- 34 n) Please provide a copy of all YEC's policies or procedures related to depreciation
35 expense, clarifying whether the document(s) have considered the provisions in
36 Tab 9 Net Salvage Study.

o) If YEC cannot provide a response to part (n), please explain on what basis YEC's revenue requirement has provided for the collection of annual net salvage expense in the amount of \$0.350 million per year as proposed in the Tab 9 Net Salvage Study and shown on Tab 3, Table 3.13.

p) Please provide a copy of the "GP Users Manual for Property Plant and Equipment."

ANSWER:

(a)

A copy of IAS 16 Property Plant and Equipment is included as YUB-YEC-1-65a Attachment 1 IAS 16 Property Plant and Equipment.

(b)

No, the threshold has not changed.

(c)

Northwest Territories Power Corporation's capitalization threshold is also \$1,000.

(d)

If an old asset is replaced by a new asset, such as if the old asset fails, the new asset will be capitalized at its cost and the old asset, which is no longer in-service, has its net book value written down to \$0.

This receives the same treatment as when an asset is retired, or if it is no longer used or useful. The only difference is these two transactions do not say whether or not there will be a new asset to take place of the retired or asset that is no longer used or useful.

As an example, in 2024 Yukon Energy determined that a Protection Relay Test Set was not working properly so it was replaced by a new Protection Relay Test Set. The old Protection Relay Test Set was derecognized with the below entry.

<Debit> Loss on disposal	\$46,000
<Debit> Accumulated depreciation	\$17,000
<Credit> Asset	\$63,000

1 **(e)**

2
3 No, part (s) of acquisition costs is not related to the net salvage methodology, but instead
4 it relates to the accounting term 'asset retirement obligations.' In accordance with IAS 37
5 Provisions, Contingent Liabilities and Contingent Assets, there may be rare situations
6 where an entity is required to record a liability for expected decommissioning costs that
7 may occur in the future. In that situation, the entity would also record an asset in
8 accordance with IAS 16. The Office of the Auditor General of Canada agrees with Yukon
9 Energy that it does not have any asset retirement obligations that need to be recorded.

10
11 **(f)**

12
13 For situations where it is appropriate to recognize an asset retirement obligation, the entry
14 would be to record a liability (credit) for the asset retirement obligation and an offsetting
15 asset (debit) for the net present value of the expected future costs. As these debits and
16 credits offset, there is no pre-collection.

17
18 **(g)**

19
20 Certain items may be capitalized regardless of cost of that individual item in situations
21 where the usual activity is to install multiple units of that item. Also, while the cost of the
22 individual item may not be significant, the installation costs could be significant. Northwest
23 Territories Power Corporation's treatment is similar.

24
25 **(h)**

26
27 Yes.

28
29 **(i)**

30 Yukon Energy would expense the amount if the cost of the intangible asset, regulatory or
31 licensing project, capital lease or critical spare was less than \$1,000.

32
33 **(j) and (k)**

34
35 An asset is capitalized into Yukon Energy's rate base and depreciation of an asset begins
36 when it is available for use, i.e., when it is in the location and condition necessary for it to
37 be capable of operating in the manner intended by management. This is not specifically

identified in Yukon Energy's accounting policies; however, it is consistent with IAS 16 paragraph 55.

(l)

As per FX-004, AFUDC is imputed interest applied to capital projects during construction. AFUDC ceases when the asset is complete and in service.

Regarding rate base, mid-year rate base and the calculation of return on mid-year rate base, Yukon Energy does not have accounting policies for these regulatory items. The accounting used for these items are based on regulatory precedence as developed over time through various regulatory filings, such as GRA's, and the Board Orders subsequently issued for those filings.

(m)

As discussed in part (j), depreciation of an asset begins when it is available for use, i.e., when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. This is not specifically identified in Yukon Energy's accounting policies; however, it is consistent with IAS 16 paragraph 55. There is no difference between financial accounting and regulatory accounting treatment (when determining Yukon Energy's regulatory return for the year). However, due to Board concerns with Yukon Energy's depreciation methodology for rate setting purposes, Yukon Energy is proposing a change in depreciation method for rate setting purposes as detailed in section 3.4.1 starting on PDF page 93 of the application. Example depreciation expense calculations as requested are shown below for financial accounting, regulatory accounting and (proposed) rate setting purposes.

		Financial Accounting	Regulatory Accounting
a	Cost	\$ 2,000.00	\$ 2,000.00
b	Service life (years)	15.00	15.00
c=a/b	Depreciation per year	\$ 133.33	\$ 133.33
d	Date at end of year	31-Dec-25	31-Dec-25
e	Acquisition date	15-Feb-25	15-Feb-25
f=d-e	Days in-service in 2025	319	319
g=c*f/365	2025 depreciation	\$ 116.53	\$ 116.53
h=c	2026 depreciation	\$ 133.33	\$ 133.33
i=c	2027 depreciation	\$ 133.33	\$ 133.33

		Proposed Rate Setting
a	Cost at beginning of 2025	\$ -
b	Cost at end of 2025	\$ 2,000.00
c	Cost at end of 2026	\$ 2,000.00
d	Cost at end of 2027	\$ 2,000.00
e	Service life (years)	15.00
f=(a+b)/2/e	2025 depreciation	\$ 66.67
g=(b+c)/2/e	2026 depreciation	\$ 133.33
h=(c+d)/2/e	2027 depreciation	\$ 133.33

1 **(n)**

2
3 Section 11.0 of FX-001 Criteria for Capitalization on PDF page 438 of the Application
4 states “Assets are depreciated based on the estimated useful life of the assigned asset
5 class as per the ‘GP Users Manual for Property Plant and Equipment’. Estimated useful
6 lives are re-evaluated as required via a third-party depreciation study.” There are no other
7 policies or procedures referencing depreciation.

8
9 Depreciation of an asset is not impacted by provisions in Tab 9 Net Salvage Study. The
10 recommendation resulting from the Net Salvage Study in Tab 9 is that revenue
11 requirement should include an overall additional \$350,000 per year of depreciation to build
12 up the Reserve for Site Restoration account.

13
14 **(o)**

15
16 Yukon Energy’s revenue requirement has provided for the collection of annual net salvage
17 expense in the amount of \$0.350 million per year on the basis that the balance of the
18 Reserve for Site Restoration is currently at an insufficient level, and therefore, should be
19 increased to an industry standard level, as summarized in section 3.4.5 on PDF page 100
20 of the application and as detailed in the Tab 9 Net Salvage Study and shown on Tab 3,
21 Table 3.13.

22
23 **(p)**

24
25 See YUB-YEC-1-65(p) Attachment 1.

Accounting >> Part I – IFRS® Standards >> 2023 Edition >> IFRS® Standards in effect on January 1, 2023 >> IAS 16
Property, plant and equipment

INTERNATIONAL ACCOUNTING STANDARD 16

property, plant and equipment

CONTENTS	Paragraph
OBJECTIVE	1
SCOPE	2
DEFINITIONS	6
RECOGNITION	7
Initial costs	11
Subsequent costs	12
MEASUREMENT AT RECOGNITION	15
Elements of cost	16
Measurement of cost	23
MEASUREMENT AFTER RECOGNITION	29
Cost model	30
Revaluation model	31
Depreciation	43
Depreciable amount and depreciation period	50
Depreciation method	60
Impairment	63
Compensation for impairment	65
DERECOGNITION	67
DISCLOSURE	73
TRANSITIONAL PROVISIONS	80
EFFECTIVE DATE	81
WITHDRAWAL OF OTHER PRONOUNCEMENTS	82

Objective

1 The objective of this Standard is to prescribe the accounting treatment for property, plant and equipment so that users of the financial statements can discern information about an entity's investment in its property, plant and equipment and the changes in such investment. The principal issues in accounting for property, plant and equipment are the recognition of the assets, the determination of their carrying amounts and the depreciation charges and impairment losses to be recognised in relation to them.

Scope

2 **This Standard shall be applied in accounting for property, plant and equipment except when another Standard requires or permits a different accounting treatment.**

3 This Standard does not apply to:

- (a) property, plant and equipment classified as held for sale in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*.
- (b) biological assets related to agricultural activity other than bearer plants (see IAS 41 *Agriculture*). This Standard applies to bearer plants but it does not apply to the produce on bearer plants.

(c) the recognition and measurement of exploration and evaluation assets (see IFRS 6 *Exploration for and Evaluation of Mineral Resources*).

(d) mineral rights and mineral reserves such as oil, natural gas and similar non-regenerative resources.

However, this Standard applies to property, plant and equipment used to develop or maintain the assets described in (b)–(d).

4 [Deleted]

5 An entity using the cost model for investment property in accordance with IAS 40 *Investment Property* shall use the cost model in this Standard for owned investment property.

Definitions

6 The following terms are used in this Standard with the meanings specified:

A bearer plant is a living plant that:

- (a) is used in the production or supply of agricultural produce;
- (b) is expected to bear produce for more than one period; and
- (c) has a remote likelihood of being sold as agricultural produce, except for incidental scrap sales.

(Paragraphs 5A–5B of IAS 41 elaborate on this definition of a bearer plant.)

Carrying amount is the amount at which an asset is recognised after deducting any accumulated depreciation and accumulated impairment losses.

Cost is the amount of cash or cash equivalents paid or the fair value of the other consideration given to acquire an asset at the time of its acquisition or construction or, where applicable, the amount attributed to that asset when initially recognised in accordance with the specific requirements of other IFRSs, eg IFRS 2 *Share-based Payment*.

Depreciable amount is the cost of an asset, or other amount substituted for cost, less its residual value.

Depreciation is the systematic allocation of the depreciable amount of an asset over its useful life.

Entity-specific value is the present value of the cash flows an entity expects to arise from the continuing use of an asset and from its disposal at the end of its useful life or expects to incur when settling a liability.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (See IFRS 13 *Fair Value Measurement*.)

An impairment loss is the amount by which the carrying amount of an asset exceeds its recoverable amount.

Property, plant and equipment are tangible items that:

- (a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and
- (b) are expected to be used during more than one period.

Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use.

The residual value of an asset is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.

Useful life is:

- (a) the period over which an asset is expected to be available for use by an entity; or
- (b) the number of production or similar units expected to be obtained from the asset by an entity.

Recognition

7 The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if:

- (a) it is probable that future economic benefits associated with the item will flow to the entity; and
- (b) the cost of the item can be measured reliably.

8 Items such as spare parts, stand-by equipment and servicing equipment are recognised in accordance with this IFRS when they meet the definition of property, plant and equipment. Otherwise, such items are classified as inventory.

9 This Standard does not prescribe the unit of measure for recognition, ie what constitutes an item of property, plant and equipment. Thus, judgement is required in applying the recognition criteria to an entity's specific circumstances. It may be appropriate to aggregate individually insignificant items, such as moulds, tools and dies, and to apply the criteria to the aggregate value.

10 An entity evaluates under this recognition principle all its property, plant and equipment costs at the time they are incurred. These costs include costs incurred initially to acquire or construct an item of property, plant and equipment and costs incurred subsequently to add to, replace part of, or service it. The cost of an item of property, plant and equipment may include costs incurred relating to leases of assets that are used to construct, add to, replace part of or service an item of property, plant and equipment, such as depreciation of right-of-use assets.

Initial costs

11 Items of property, plant and equipment may be acquired for safety or environmental reasons. The acquisition of such property, plant and equipment, although not directly increasing the future economic benefits of any particular existing item of property, plant and equipment, may be necessary for an entity to obtain the future economic benefits from its other assets. Such items of property, plant and equipment qualify for recognition as assets because they enable an entity to derive future economic benefits from related assets in excess of what could be derived had those items not been acquired. For example, a chemical manufacturer may install new chemical handling processes to comply with environmental requirements for the production and storage of dangerous chemicals; related plant enhancements are recognised as an asset because without them the entity is unable to manufacture and sell chemicals. However, the resulting carrying amount of such an asset and related assets is reviewed for impairment in accordance with IAS 36 *Impairment of Assets*.

Subsequent costs

12 Under the recognition principle in paragraph 7, an entity does not recognise in the carrying amount of an item of property, plant and equipment the costs of the day-to-day servicing of the item. Rather, these costs are recognised in profit or loss as incurred. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. The purpose of these expenditures is often described as for the 'repairs and maintenance' of the item of property, plant and equipment.

13 Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, a furnace may require relining after a specified number of hours of use, or aircraft interiors such as seats and galleys may require replacement several times during the life of the airframe. Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a nonrecurring replacement. Under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met. The carrying amount of those parts that are replaced is derecognised in accordance with the derecognition provisions of this Standard (see paragraphs 67–72).

14 A condition of continuing to operate an item of property, plant and equipment (for example, an aircraft) may be performing regular major inspections for faults regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised. This occurs regardless of whether the cost of the previous inspection was identified in the transaction in which the item was acquired or constructed. If necessary, the estimated cost of a future similar inspection may be used as an indication of what the cost of the existing inspection component was when the item was acquired or constructed.

Measurement at recognition

15 An item of property, plant and equipment that qualifies for recognition as an asset shall be measured at its cost.

Elements of cost

16 The cost of an item of property, plant and equipment comprises:

- (a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
- (b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.
- (c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

17 Examples of directly attributable costs are:

- (a) costs of employee benefits (as defined in IAS 19 *Employee Benefits*) arising directly from the construction or acquisition of the item of property, plant and equipment;
- (b) costs of site preparation;
- (c) initial delivery and handling costs;
- (d) installation and assembly costs;
- (e) costs of testing whether the asset is functioning properly (ie assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes); and
- (f) professional fees.

18 An entity applies IAS 2 *Inventories* to the costs of obligations for dismantling, removing and restoring the site on which an item is located that are incurred during a particular period as a consequence of having used the item to produce

inventories during that period. The obligations for costs accounted for in accordance with IAS 2 or IAS 16 are recognised and measured in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*.

19 Examples of costs that are not costs of an item of property, plant and equipment are:

- (a) costs of opening a new facility;
- (b) costs of introducing a new product or service (including costs of advertising and promotional activities);
- (c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
- (d) administration and other general overhead costs.

20 Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item are not included in the carrying amount of that item. For example, the following costs are not included in the carrying amount of an item of property, plant and equipment:

- (a) costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;
- (b) initial operating losses, such as those incurred while demand for the item's output builds up; and
- (c) costs of relocating or reorganising part or all of an entity's operations.

20A Items may be produced while bringing an item of property, plant and equipment to the location and condition necessary for it to be capable of operating in the manner intended by management (such as samples produced when testing whether the asset is functioning properly). An entity recognises the proceeds from selling any such items, and the cost of those items, in profit or loss in accordance with applicable Standards. The entity measures the cost of those items applying the measurement requirements of IAS 2.

21 Some operations occur in connection with the construction or development of an item of property, plant and equipment, but are not necessary to bring the item to the location and condition necessary for it to be capable of operating in the manner intended by management. These incidental operations may occur before or during the construction or development activities. For example, income may be earned through using a building site as a car park until construction starts. Because incidental operations are not necessary to bring an item to the location and condition necessary for it to be capable of operating in the manner intended by management, the income and related expenses of incidental operations are recognised in profit or loss and included in their respective classifications of income and expense.

22 The cost of a self-constructed asset is determined using the same principles as for an acquired asset. If an entity makes similar assets for sale in the normal course of business, the cost of the asset is usually the same as the cost of constructing an asset for sale (see IAS 2). Therefore, any internal profits are eliminated in arriving at such costs. Similarly, the cost of abnormal amounts of wasted material, labour, or other resources incurred in self-constructing an asset is not included in the cost of the asset. IAS 23 *Borrowing Costs* establishes criteria for the recognition of interest as a component of the carrying amount of a self-constructed item of property, plant and equipment.

22A Bearer plants are accounted for in the same way as self-constructed items of property, plant and equipment before they are in the location and condition necessary to be capable of operating in the manner intended by management. Consequently, references to 'construction' in this Standard should be read as covering activities that are necessary to cultivate the bearer plants before they are in the location and condition necessary to be capable of operating in the manner intended by management.

Measurement of cost

23 The cost of an item of property, plant and equipment is the cash price equivalent at the recognition date. If payment is deferred beyond normal credit terms, the difference between the cash price equivalent and the total payment is recognised as interest over the period of credit unless such interest is capitalised in accordance with IAS 23.

24 One or more items of property, plant and equipment may be acquired in exchange for a non-monetary asset or assets, or a combination of monetary and non-monetary assets. The following discussion refers simply to an exchange of one non-monetary asset for another, but it also applies to all exchanges described in the preceding sentence. The cost of such an item of property, plant and equipment is measured at fair value unless (a) the exchange transaction lacks commercial substance or (b) the fair value of neither the asset received nor the asset given up is reliably measurable. The acquired item is measured in this way even if an entity cannot immediately derecognise the asset given up. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up.

25 An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. An exchange transaction has commercial substance if:

- (a) the configuration (risk, timing and amount) of the cash flows of the asset received differs from the configuration of the cash flows of the asset transferred; or
- (b) the entity-specific value of the portion of the entity's operations affected by the transaction changes as a result of the exchange; and

- (c) the difference in (a) or (b) is significant relative to the fair value of the assets exchanged.

For the purpose of determining whether an exchange transaction has commercial substance, the entity-specific value of the portion of the entity's operations affected by the transaction shall reflect post-tax cash flows. The result of these analyses may be clear without an entity having to perform detailed calculations.

26 The fair value of an asset is reliably measurable if (a) the variability in the range of reasonable fair value measurements is not significant for that asset or (b) the probabilities of the various estimates within the range can be reasonably assessed and used when measuring fair value. If an entity is able to measure reliably the fair value of either the asset received or the asset given up, then the fair value of the asset given up is used to measure the cost of the asset received unless the fair value of the asset received is more clearly evident.

27 [Deleted]

28 The carrying amount of an item of property, plant and equipment may be reduced by government grants in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*.

Measurement after recognition

29 An entity shall choose either the cost model in paragraph 30 or the revaluation model in paragraph 31 as its accounting policy and shall apply that policy to an entire class of property, plant and equipment.

29A Some entities operate, either internally or externally, an investment fund that provides investors with benefits determined by units in the fund. Similarly, some entities issue groups of insurance contracts with direct participation features and hold the underlying items. Some such funds or underlying items include owner-occupied property. The entity applies IAS 16 to owner-occupied properties that are included in such a fund or are underlying items. Despite paragraph 29, the entity may elect to measure such properties using the fair value model in accordance with IAS 40. For the purposes of this election, insurance contracts include investment contracts with discretionary participation features. (See IFRS 17 *Insurance Contracts* for terms used in this paragraph that are defined in that Standard).

29B An entity shall treat owner-occupied property measured using the investment property fair value model applying paragraph 29A as a separate class of property, plant and equipment.

Cost model

30 After recognition as an asset, an item of property, plant and equipment shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation model

31 After recognition as an asset, an item of property, plant and equipment whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. Revaluations shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair value at the end of the reporting period.

32–33 [Deleted]

34 The frequency of revaluations depends upon the changes in fair values of the items of property, plant and equipment being revalued. When the fair value of a revalued asset differs materially from its carrying amount, a further revaluation is required. Some items of property, plant and equipment experience significant and volatile changes in fair value, thus necessitating annual revaluation. Such frequent revaluations are unnecessary for items of property, plant and equipment with only insignificant changes in fair value. Instead, it may be necessary to revalue the item only every three or five years.

35 When an item of property, plant and equipment is revalued, the carrying amount of that asset is adjusted to the revalued amount. At the date of the revaluation, the asset is treated in one of the following ways:

- (a) the gross carrying amount is adjusted in a manner that is consistent with the revaluation of the carrying amount of the asset. For example, the gross carrying amount may be restated by reference to observable market data or it may be restated proportionately to the change in the carrying amount. The accumulated depreciation at the date of the revaluation is adjusted to equal the difference between the gross carrying amount and the carrying amount of the asset after taking into account accumulated impairment losses; or
- (b) the accumulated depreciation is eliminated against the gross carrying amount of the asset.

The amount of the adjustment of accumulated depreciation forms part of the increase or decrease in carrying amount that is accounted for in accordance with paragraphs 39 and 40.

36 If an item of property, plant and equipment is revalued, the entire class of property, plant and equipment to which that asset belongs shall be revalued.

37 A class of property, plant and equipment is a grouping of assets of a similar nature and use in an entity's operations. The following are examples of separate classes:

- (a) land;
- (b) land and buildings;
- (c) machinery;

- (d) ships;
- (e) aircraft;
- (f) motor vehicles;
- (g) furniture and fixtures;
- (h) office equipment; and
- (i) bearer plants.

38 The items within a class of property, plant and equipment are revalued simultaneously to avoid selective revaluation of assets and the reporting of amounts in the financial statements that are a mixture of costs and values as at different dates. However, a class of assets may be revalued on a rolling basis provided revaluation of the class of assets is completed within a short period and provided the revaluations are kept up to date.

39 If an asset's carrying amount is increased as a result of a revaluation, the increase shall be recognised in other comprehensive income and accumulated in equity under the heading of revaluation surplus. However, the increase shall be recognised in profit or loss to the extent that it reverses a revaluation decrease of the same asset previously recognised in profit or loss.

40 If an asset's carrying amount is decreased as a result of a revaluation, the decrease shall be recognised in profit or loss. However, the decrease shall be recognised in other comprehensive income to the extent of any credit balance existing in the revaluation surplus in respect of that asset. The decrease recognised in other comprehensive income reduces the amount accumulated in equity under the heading of revaluation surplus.

41 The revaluation surplus included in equity in respect of an item of property, plant and equipment may be transferred directly to retained earnings when the asset is derecognised. This may involve transferring the whole of the surplus when the asset is retired or disposed of. However, some of the surplus may be transferred as the asset is used by an entity. In such a case, the amount of the surplus transferred would be the difference between depreciation based on the revalued carrying amount of the asset and depreciation based on the asset's original cost. Transfers from revaluation surplus to retained earnings are not made through profit or loss.

42 The effects of taxes on income, if any, resulting from the revaluation of property, plant and equipment are recognised and disclosed in accordance with IAS 12 *Income Taxes*.

Depreciation

43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

44 An entity allocates the amount initially recognised in respect of an item of property, plant and equipment to its significant parts and depreciates separately each such part. For example, it may be appropriate to depreciate separately the airframe and engines of an aircraft. Similarly, if an entity acquires property, plant and equipment subject to an operating lease in which it is the lessor, it may be appropriate to depreciate separately amounts reflected in the cost of that item that are attributable to favourable or unfavourable lease terms relative to market terms.

45 A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

46 To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item. The remainder consists of the parts of the item that are individually not significant. If an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life of its parts.

47 An entity may choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item.

48 The depreciation charge for each period shall be recognised in profit or loss unless it is included in the carrying amount of another asset.

49 The depreciation charge for a period is usually recognised in profit or loss. However, sometimes, the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the depreciation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, the depreciation of manufacturing plant and equipment is included in the costs of conversion of inventories (see IAS 2). Similarly, depreciation of property, plant and equipment used for development activities may be included in the cost of an intangible asset recognised in accordance with IAS 38 *Intangible Assets*.

Depreciable amount and depreciation period

50 The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.

51 The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*.

52 Depreciation is recognised even if the fair value of the asset exceeds its carrying amount, as long as the asset's residual value does not exceed its carrying amount. Repair and maintenance of an asset do not negate the need to depreciate it.

53 The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

54 The residual value of an asset may increase to an amount equal to or greater than the asset's carrying amount. If it does, the asset's depreciation charge is zero unless and until its residual value subsequently decreases to an amount below the asset's carrying amount.

55 Depreciation of an asset begins when it is available for use, ie when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5 and the date that the asset is derecognised. Therefore, depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated. However, under usage methods of depreciation the depreciation charge can be zero while there is no production.

56 The future economic benefits embodied in an asset are consumed by an entity principally through its use. However, other factors, such as technical or commercial obsolescence and wear and tear while an asset remains idle, often result in the diminution of the economic benefits that might have been obtained from the asset. Consequently, all the following factors are considered in determining the useful life of an asset:

- (a) expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
- (b) expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance programme, and the care and maintenance of the asset while idle.
- (c) technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset. Expected future reductions in the selling price of an item that was produced using an asset could indicate the expectation of technical or commercial obsolescence of the asset, which, in turn, might reflect a reduction of the future economic benefits embodied in the asset.
- (d) legal or similar limits on the use of the asset, such as the expiry dates of related leases.

57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.

58 Land and buildings are separable assets and are accounted for separately, even when they are acquired together. With some exceptions, such as quarries and sites used for landfill, land has an unlimited useful life and therefore is not depreciated. Buildings have a limited useful life and therefore are depreciable assets. An increase in the value of the land on which a building stands does not affect the determination of the depreciable amount of the building.

59 If the cost of land includes the costs of site dismantlement, removal and restoration, that portion of the land asset is depreciated over the period of benefits obtained by incurring those costs. In some cases, the land itself may have a limited useful life, in which case it is depreciated in a manner that reflects the benefits to be derived from it.

Depreciation method

60 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.

61 The depreciation method applied to an asset shall be reviewed at least at each financial year-end and, if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method shall be changed to reflect the changed pattern. Such a change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

62 A variety of depreciation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the units of production method. Straight-line depreciation results in a constant charge over the useful life if the asset's residual value does not change. The diminishing balance method results in a decreasing charge over the useful life. The units of production method results in a charge based on the expected use or output. The entity selects the method that most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. That method is applied consistently from period to period unless there is a change in the expected pattern of consumption of those future economic benefits.

62A A depreciation method that is based on revenue that is generated by an activity that includes the use of an asset is not appropriate. The revenue generated by an activity that includes the use of an asset generally reflects factors other than the consumption of the economic benefits of the asset. For example, revenue is affected by other inputs and

processes, selling activities and changes in sales volumes and prices. The price component of revenue may be affected by inflation, which has no bearing upon the way in which an asset is consumed.

Impairment

63 To determine whether an item of property, plant and equipment is impaired, an entity applies IAS 36 *Impairment of Assets*. That Standard explains how an entity reviews the carrying amount of its assets, how it determines the recoverable amount of an asset, and when it recognises, or reverses the recognition of, an impairment loss.

64 [Deleted]

Compensation for impairment

65 Compensation from third parties for items of property, plant and equipment that were impaired, lost or given up shall be included in profit or loss when the compensation becomes receivable.

66 Impairments or losses of items of property, plant and equipment, related claims for or payments of compensation from third parties and any subsequent purchase or construction of replacement assets are separate economic events and are accounted for separately as follows:

- (a) impairments of items of property, plant and equipment are recognised in accordance with IAS 36;
- (b) derecognition of items of property, plant and equipment retired or disposed of is determined in accordance with this Standard;
- (c) compensation from third parties for items of property, plant and equipment that were impaired, lost or given up is included in determining profit or loss when it becomes receivable; and
- (d) the cost of items of property, plant and equipment restored, purchased or constructed as replacements is determined in accordance with this Standard.

Derecognition

67 The carrying amount of an item of property, plant and equipment shall be derecognised:

- (a) on disposal; or
- (b) when no future economic benefits are expected from its use or disposal.

68 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognised (unless IFRS 16 *Leases* requires otherwise on a sale and leaseback). Gains shall not be classified as revenue.

68A However, an entity that, in the course of its ordinary activities, routinely sells items of property, plant and equipment that it has held for rental to others shall transfer such assets to inventories at their carrying amount when they cease to be rented and become held for sale. The proceeds from the sale of such assets shall be recognised as revenue in accordance with IFRS 15 *Revenue from Contracts with Customers*. IFRS 5 does not apply when assets that are held for sale in the ordinary course of business are transferred to inventories.

69 The disposal of an item of property, plant and equipment may occur in a variety of ways (eg by sale, by entering into a finance lease or by donation). The date of disposal of an item of property, plant and equipment is the date the recipient obtains control of that item in accordance with the requirements for determining when a performance obligation is satisfied in IFRS 15. IFRS 16 applies to disposal by a sale and leaseback.

70 If, under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of a replacement for part of the item, then it derecognises the carrying amount of the replaced part regardless of whether the replaced part had been depreciated separately. If it is not practicable for an entity to determine the carrying amount of the replaced part, it may use the cost of the replacement as an indication of what the cost of the replaced part was at the time it was acquired or constructed.

71 The gain or loss arising from the derecognition of an item of property, plant and equipment shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

72 The amount of consideration to be included in the gain or loss arising from the derecognition of an item of property, plant and equipment is determined in accordance with the requirements for determining the transaction price in paragraphs 47–72 of IFRS 15. Subsequent changes to the estimated amount of the consideration included in the gain or loss shall be accounted for in accordance with the requirements for changes in the transaction price in IFRS 15.

Disclosure

73 The financial statements shall disclose, for each class of property, plant and equipment:

- (a) the measurement bases used for determining the gross carrying amount;
- (b) the depreciation methods used;
- (c) the useful lives or the depreciation rates used;
- (d) the gross carrying amount and the accumulated depreciation (aggregated with accumulated impairment losses) at the beginning and end of the period; and
- (e) a reconciliation of the carrying amount at the beginning and end of the period showing:

- (i) additions;
- (ii) assets classified as held for sale or included in a disposal group classified as held for sale in accordance with IFRS 5 and other disposals;
- (iii) acquisitions through business combinations;
- (iv) increases or decreases resulting from revaluations under paragraphs 31, 39 and 40 and from impairment losses recognised or reversed in other comprehensive income in accordance with IAS 36;
- (v) impairment losses recognised in profit or loss in accordance with IAS 36;
- (vi) impairment losses reversed in profit or loss in accordance with IAS 36;
- (vii) depreciation;
- (viii) the net exchange differences arising on the translation of the financial statements from the functional currency into a different presentation currency, including the translation of a foreign operation into the presentation currency of the reporting entity; and
- (ix) other changes.

74 The financial statements shall also disclose:

- (a) the existence and amounts of restrictions on title, and property, plant and equipment pledged as security for liabilities;
- (b) the amount of expenditures recognised in the carrying amount of an item of property, plant and equipment in the course of its construction; and
- (c) the amount of contractual commitments for the acquisition of property, plant and equipment.

74A If not presented separately in the statement of comprehensive income, the financial statements shall also disclose:

- (a) the amount of compensation from third parties for items of property, plant and equipment that were impaired, lost or given up that is included in profit or loss; and
- (b) the amounts of proceeds and cost included in profit or loss in accordance with paragraph 20A that relate to items produced that are not an output of the entity's ordinary activities, and which line item(s) in the statement of comprehensive income include(s) such proceeds and cost.

75 Selection of the depreciation method and estimation of the useful life of assets are matters of judgement. Therefore, disclosure of the methods adopted and the estimated useful lives or depreciation rates provides users of financial statements with information that allows them to review the policies selected by management and enables comparisons to be made with other entities. For similar reasons, it is necessary to disclose:

- (a) depreciation, whether recognised in profit or loss or as a part of the cost of other assets, during a period; and
- (b) accumulated depreciation at the end of the period.

76 In accordance with IAS 8 an entity discloses the nature and effect of a change in an accounting estimate that has an effect in the current period or is expected to have an effect in subsequent periods. For property, plant and equipment, such disclosure may arise from changes in estimates with respect to:

- (a) residual values;
- (b) the estimated costs of dismantling, removing or restoring items of property, plant and equipment;
- (c) useful lives; and
- (d) depreciation methods.

77 If items of property, plant and equipment are stated at revalued amounts, the following shall be disclosed in addition to the disclosures required by IFRS 13:

- (a) the effective date of the revaluation;
- (b) whether an independent valuer was involved;
- (c) [deleted]
- (d) [deleted]
- (e) for each revalued class of property, plant and equipment, the carrying amount that would have been recognised had the assets been carried under the cost model; and
- (f) the revaluation surplus, indicating the change for the period and any restrictions on the distribution of the balance to shareholders.

78 In accordance with IAS 36 an entity discloses information on impaired property, plant and equipment in addition to the information required by paragraph 73(e)(iv)–(vi).

79 Users of financial statements may also find the following information relevant to their needs:

- (a) the carrying amount of temporarily idle property, plant and equipment;

- (b) the gross carrying amount of any fully depreciated property, plant and equipment that is still in use;
- (c) the carrying amount of property, plant and equipment retired from active use and not classified as held for sale in accordance with IFRS 5; and
- (d) when the cost model is used, the fair value of property, plant and equipment when this is materially different from the carrying amount.

Therefore, entities are encouraged to disclose these amounts.

Transitional provisions

80 The requirements of paragraphs 24–26 regarding the initial measurement of an item of property, plant and equipment acquired in an exchange of assets transaction shall be applied prospectively only to future transactions.

80A Paragraph 35 was amended by *Annual Improvements to IFRSs 2010–2012 Cycle*. An entity shall apply that amendment to all revaluations recognised in annual periods beginning on or after the date of initial application of that amendment and in the immediately preceding annual period. An entity may also present adjusted comparative information for any earlier periods presented, but it is not required to do so. If an entity presents unadjusted comparative information for any earlier periods, it shall clearly identify the information that has not been adjusted, state that it has been presented on a different basis and explain that basis.

80B In the reporting period when *Agriculture: Bearer Plants* (Amendments to IAS 16 and IAS 41) is first applied an entity need not disclose the quantitative information required by paragraph 28(f) of IAS 8 for the current period. However, an entity shall present the quantitative information required by paragraph 28(f) of IAS 8 for each prior period presented.

80C An entity may elect to measure an item of bearer plants at its fair value at the beginning of the earliest period presented in the financial statements for the reporting period in which the entity first applies *Agriculture: Bearer Plants* (Amendments to IAS 16 and IAS 41) and use that fair value as its deemed cost at that date. Any difference between the previous carrying amount and fair value shall be recognised in opening retained earnings at the beginning of the earliest period presented.

80D *Property, Plant and Equipment—Proceeds before Intended Use*, issued in May 2020, amended paragraphs 17 and 74 and added paragraphs 20A and 74A. An entity shall apply those amendments retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments. The entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the beginning of that earliest period presented.

Effective date

81 An entity shall apply this Standard for annual periods beginning on or after 1 January 2005. Earlier application is encouraged. If an entity applies this Standard for a period beginning before 1 January 2005, it shall disclose that fact.

81A An entity shall apply the amendments in paragraph 3 for annual periods beginning on or after 1 January 2006. If an entity applies IFRS 6 for an earlier period, those amendments shall be applied for that earlier period.

81B IAS 1 *Presentation of Financial Statements* (as revised in 2007) amended the terminology used throughout IFRSs. In addition it amended paragraphs 39, 40 and 73(e)(iv). An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. If an entity applies IAS 1 (revised 2007) for an earlier period, the amendments shall be applied for that earlier period.

81C IFRS 3 *Business Combinations* (as revised in 2008) amended paragraph 44. An entity shall apply that amendment for annual periods beginning on or after 1 July 2009. If an entity applies IFRS 3 (revised 2008) for an earlier period, the amendment shall also be applied for that earlier period.

81D Paragraphs 6 and 69 were amended and paragraph 68A was added by *Improvements to IFRSs* issued in May 2008. An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. Earlier application is permitted. If an entity applies the amendments for an earlier period it shall disclose that fact and at the same time apply the related amendments to IAS 7 *Statement of Cash Flows*.

81E Paragraph 5 was amended by *Improvements to IFRSs* issued in May 2008. An entity shall apply that amendment prospectively for annual periods beginning on or after 1 January 2009. Earlier application is permitted if an entity also applies the amendments to paragraphs 8, 9, 22, 48, 53, 53A, 53B, 54, 57 and 85B of IAS 40 at the same time. If an entity applies the amendment for an earlier period it shall disclose that fact.

81F IFRS 13, issued in May 2011, amended the definition of fair value and the definition of recoverable amount in paragraph 6, amended paragraphs 26, 35 and 77 and deleted paragraphs 32 and 33. An entity shall apply those amendments when it applies IFRS 13.

81G *Annual Improvements 2009–2011 Cycle*, issued in May 2012, amended paragraph 8. An entity shall apply that amendment retrospectively in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*

for annual periods beginning on or after 1 January 2013. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

81H *Annual Improvements to IFRSs 2010–2012 Cycle*, issued in December 2013, amended paragraph 35 and added paragraph 80A. An entity shall apply that amendment for annual periods beginning on or after 1 July 2014. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

81I *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), issued in May 2014, amended paragraph 56 and added paragraph 62A. An entity shall apply those amendments prospectively for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies those amendments for an earlier period it shall disclose that fact.

81J *IFRS 15 Revenue from Contracts with Customers*, issued in May 2014, amended paragraphs 68A, 69 and 72. An entity shall apply those amendments when it applies IFRS 15.

81K *Agriculture: Bearer Plants* (Amendments to IAS 16 and IAS 41), issued in June 2014, amended paragraphs 3, 6 and 37 and added paragraphs 22A and 80B–80C. An entity shall apply those amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies those amendments for an earlier period, it shall disclose that fact. An entity shall apply those amendments retrospectively, in accordance with IAS 8, except as specified in paragraph 80C.

81L *IFRS 16*, issued in January 2016, deleted paragraphs 4 and 27 and amended paragraphs 5, 10, 44 and 68–69. An entity shall apply those amendments when it applies IFRS 16.

81M *IFRS 17*, issued in May 2017, added paragraphs 29A and 29B. An entity shall apply those amendments when it applies IFRS 17.

81N *Property, Plant and Equipment—Proceeds before Intended Use*, issued in May 2020, amended paragraphs 17 and 74, and added paragraphs 20A, 74A and 80D. An entity shall apply those amendments for annual reporting periods beginning on or after 1 January 2022. Earlier application is permitted. If an entity applies those amendments for an earlier period, it shall disclose that fact.

Withdrawal of other pronouncements

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- 82 This Standard supersedes IAS 16 *Property, Plant and Equipment* (revised in 1998).
- 83 This Standard supersedes the following Interpretations:
- (a) SIC-6 *Costs of Modifying Existing Software*;
 - (b) SIC-14 *Property, Plant and Equipment — Compensation for the Impairment or Loss of Items*; and
 - (c) SIC-23 *Property, Plant and Equipment — Major Inspection or Overhaul Costs*.
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Fixed Assets

Table of Contents

Fixed Assets Coding Structure 2
 Account Definition 2
Net Differences 33
Accumulated Depreciation.....34
Fixed Asset Unit Numbers.....39

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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Fixed Assets Coding Structure

Account Definition

GP uses a subledger system which assigns a class ID to each asset. The assets then roll up from the class ID to the GL.

The following is the GL code which precedes the Class ID's that are assigned to the GL Code. For each Class ID there is a bit of description on what types of asset would be included.

PROPERTY, PLANT & EQUIPMENT

GL Code

0000-000-1610 LAND

Class ID

1610-003	Land Hydro Production Land associated with hydro production plant.
1610-004	Land Diesel Production Land associated with diesel production plant.
1610-006	Land Main Transmission Facilities Land associated with main transmission facilities.
1610-008	Land Distribution System Land associated with distribution system.
1610-009	Land General Plant Land associated with general plant.
1610-106	Land Rights Land rights associated with general plant.
1610-110	Land – LNG Production Land associated with LNG production.

GL Code

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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0000-000-1615 HYDRO PLANT

Class ID

1615-200 Structures and Improvements (OL = 72 years)

Structures and improvements associated with hydro production plant. This would include control structure upgrades, elevator upgrades, bridge work, gate house improvements. These improvements have a longer life expectancy than those coded to 1645-200 (Buildings and Other equipment – Structures and improvements).

1615-205 Reservoirs Dams and Waterways (OL = 99 years)

This account shall include the cost of facilities used for impounding, collecting, storage, diversion, regulation and delivery of water used primarily for generating electricity. Components of cost:

1. Bridges and culverts (when not a part of structure and improvements).
2. Clearing and preparing land.
3. Dams, including waterways, spillways, flash boards, spillway gates with operating and control mechanism, tunnels, gate houses and fish ladders.
4. Dikes and embankments.
5. Electric system including conductors, control system, transformers, lighting fixtures, etc.
6. Excavation, including shoring, bracing, bridging, refill and disposal of excess excavated material.
7. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided. Intakes, including trash racks, rack cleaners, control gates and valves with operating mechanisms and intake house where not a part of station structure.
8. Platforms, railings, steps, gratings, etc. appurtenant to structures listed herein.
9. Retaining walls.
10. Water conductors and accessories, including canals, tunnels, flumes, penstocks, pipe conductors, fore bays, tailraces, navigation locks and operating mechanisms, water hammer and surge tanks and supporting trestles and structures.
11. Water storage reservoir, including dams, flash boards, spillway gates and operating mechanisms, inlet and outlet tunnels, regulating valves and valve towers, silt and mud sluicing tunnels with valve or gate towers and all other structures wholly identified with the foregoing items.

1615-206 Reservoirs Dams and Waterways Twin Assets (OL = 0 years)

This account is used to twin assets from 1615-205 Reservoirs Dams and

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GP Users Manual for Property Plant and Equipment

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Waterways. The assets in this account are not depreciated. Assets in Reservoirs, Dams and Waterways 1615-205 have a life of 103 years, however GP only allows a maximum life of 99 years. Therefore assets in this class are twinned with a suffix of 2 to account for the extra 4 years.

1615-504 Hydro Assets Overhaul (OL = 10 years)

1615-506 Waterwheels, Turbines and Generators (OL = 85 years)

This account shall include the installation costs of water wheels and hydraulic turbines (from connection with penstock or flume to tailrace) and generators driven thereby devoted to the production of electricity by water power or for production of power for industrial or other purposes, if the equipment used for such purposes is a part of the hydraulic power plant works. Components of costs:

1. Exciter water wheels and turbines, including runners (gates, governors, pressure regulators, oil pumps, operating mechanisms) scroll cases, draft tubes and draft tube supports.
2. Foundation and settings, specially constructed for and not expected to outlast the apparatus for which provided.
3. Generator cooling systems, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
4. Generators, main A.C. or D.C., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
5. Lubricating systems, including gauges, filters, tanks, pumps, piping, etc.
6. Main penstock valves and appurtenances including main valves, control equipment, by-pass valves, fittings and other accessories.
7. Main turbines and waterwheels, including runners, gates, governors, pressure regulators, oil pumps, operating mechanisms, scroll cases, draft tubes and draft tube supports.
8. Mechanical meters and recording instruments.
9. Miscellaneous water wheel equipment including gauges thermometers, meters and other instruments.
10. Platforms, railings, steps, gratings, etc. appurtenant to apparatus listed herein.
11. Scroll case filling and drain system, including gates, pipes valves, fittings, etc.
12. Water actuated pressure regulator systems, including ranks and housings, pipes, valves, fittings and insulations, piers and anchorage, excavation and backfill.

1615-600 Accessory Electric Equipment (OL = 40 years)

This account shall include the installation costs of auxiliary generating

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apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts, such motors being included in the account in which the equipment with which they are associated is included.

Note A: do not include in this account transformers and other equipment used for changing the voltage or frequency of electricity for the purpose of transmission or distribution.

Note B: when any item of equipment listed herein is used wholly to furnish power to equipment, it shall be included in such equipment accounts.

Components of cost:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks current transformers, potential transformers conductors and conduit special support for generator main leads, grounding switch, special housings, protective screens, etc. station buses, including main auxiliary, transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories voltage regulators and accessories, compensators, resistors, starting transformers, current transformers potential transformers, protective relays, storage batteries and charging equipment; isolated panels and equipment, conductors and conduit, special supports, special fire extinguishing equipment and test equipment.
4. Station control system including station switchboards with panel wiring panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, truck-type switchboards complete, cubicles, station supervisory control devices, frequency control equipment, master clocks, watt-hour meter, station

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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totalizing watt meter, storage batteries panels and charging sets, instrument and transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, etc

1615-601 Accessory Digital Equipment (OL = 20 years)

This account shall include the installation costs of digital generating apparatus, conversion equipment and equipment used primarily in connection with the control and switching of electric energy produced by hydraulic power and the protection of electric circuits and equipment.

1615-700 Miscellaneous Power Plant Equip (OL = 30 years)

This account shall include the installation costs of miscellaneous equipment in and about the hydroelectric generating plant, which is devoted to general station use and is not properly includable in other hydraulic production accounts. Components of cost:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails monorails, hoists, etc., with electric and mechanical connections.
3. Fire extinguishing equipment for general station use.
4. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
5. Miscellaneous belts, pulleys, countershafts, etc.
6. Miscellaneous equipment, including atmospheric and weather indicating devices, intra site communication equipment, laboratory equipment, insect control equipment signal systems, calla phones, emergency whistles and sirens, fire alarms and other similar equipment refrigerating system, including compressors, pumps, cooling coils, etc.
7. Station maintenance equipment including lathes, shapers, planers, drill presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.
8. Ventilating equipment, including items wholly identified with apparatus listed herein.

1615-730 Hydro Fences (OL = 40 years)

This account shall include the costs associated with fencing around Hydro plants.

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GL Code**0000-000-1620 DIESEL PRODUCTION**Class ID

- 1620-200 Structures and Improvements (OL = 72 years)**
This account shall include the costs associated with diesel production structures. These improvements have a longer life expectancy than those coded to 1645-200 (Buildings and Other equipment – structures and improvements).
- 1620-201 Building & Improvements (OL = 55 years)**
This account shall include the costs associated with diesel production buildings. These improvements include maintenance, upgrades and renovations.
- 1620-403 Fuel Holders, Products and Accessories (OL = 40 years)**
This account shall include the installation costs of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine and the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators.
Components of cost:
1. Coils.
 2. Heating piping and valves.
 3. Pumps.
 4. Fuel scrubbing equipment.
 5. Tanks and fuel oil storage.
- 1620-500 Generating Equipment and Prime (OL = 40 years)**
This account shall include the installation costs of diesel or other power driven main generators and the prime movers devoted to the generation of electric energy, together with their auxiliaries. Components of cost:
1. Air filtering system.
 2. Belting, shafting, pulleys, reduction gearing, etc.
 3. Cooling system, including items wholly identified with apparatus listed herein.
 4. Cranes, hoists, etc., including items wholly identified with apparatus listed herein.
 5. Engines, diesel, gasoline, gas or other internal combustion.
 6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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7. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
8. Generators, main A.C. or D.C., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
9. Governors.
10. Ignition system
11. Inlet valve.
12. Lubricating systems, including filters, tanks, pumps, and piping, coolers.
13. Mechanical meters, including gauges, recording instruments, sampling and testing equipment.
14. Mufflers.
15. Piping.
16. Platforms, railings, steps, grating, etc., appurtenant to apparatus listed herein.
17. Starting systems, compressed air, or other, including compressors and drives, tanks, piping, motors, boards and connections, storage tanks, etc.
18. Steelwork specially constructed for apparatus listed herein.
19. Waste heat broilers, anti-fluctuations, etc. lubricating oil (first charge) etc.

1620-504 Diesel Assets Overhaul (OL = 5 years)

1620-508 Minto Generating Equipment (OL = 12 years)

This account includes the installation costs of diesel generating equipment at Minto Mine.

1620-600 Accessory Electric Equipment (OL = 45 years)

This account shall include the installation costs of auxiliary generating apparatus, conversion equipment and equipment used primarily in connection with control and switching of electric energy produced in other power generating stations and the protection of electric circuits and equipment except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which it is associated.

Note A: Do not include in this account transformers and other equipment used for changing voltage or frequency of electric energy for the purpose of transmission or distribution.

Note B: When any item or equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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Components of cost:

1. Auxiliary generators, including boards, compartments, switching equipment, control equipment and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arrestors, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and protective relays, isolated panels and equipment, conductors and conduit, special support for generator main leads, grounding switch, special housings, protective screens, etc.
4. Station control system, including station switchboards with panel wiring. Panels with instruments and control equipment only, panels with switching equipment, mounted or mechanically connected, trunk type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature recording devices, frequency control equipment, master clocks, watt-hour meters, station totalizing wattmeter, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, etc.
5. Station buses, including main, auxiliary, transfers, synchronizing and fault ground bases, including oil circuit breakers and accessories, disconnection switches and accessories, circuit breakers and accessories, disconnection switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipments, conductors and conduit, special supports, special housings, concrete pads, general station ground system, special fire extinguishing system and test equipment.

1620-700

Miscellaneous Power Plant Equip (OL = 30 years)

This account shall include the installation costs of miscellaneous equipment in and about the other power generating plant devoted to general station use and not properly includable in any of the other foregoing power production accounts. Components of cost:

1. Compressed air and vacuum cleaning systems, including tanks,

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- compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc. with electrical and mechanical connections.
 3. Fire extinguishing equipment for general station use.
 4. Foundations and settings; specially constructed for and not expected to outlast the apparatus for which provided. Miscellaneous equipment, including devices, intra site communication equipment, laboratory equipment, signal systems, calla phones, emergency whistles and sirens, fire alarms, belts, pulley, countershafts, etc.
 5. Refrigerating system including compressors, pumps, cooling coils, etc.
 6. Station maintenance equipment, including lathes shapers, planers, drill presses, hydraulic presses, grinders, etc. with motors, shafting, hangers, pulleys, etc.
 7. Ventilating equipment including items wholly identified with apparatus listed herein.

GL Code

0000-000-1625 DISTRIBUTION SYSTEM

Class ID

1625-300 Poles and Fixtures (OL = 40 years)

This account shall include the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire.

Note: materials used for substations, including transformers, will be charged to account 1625-710 Substation Equipment.

Components of cost:

1. Anchors, head arm and other guys, including any guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Cross arms and braces.
4. Extension arms.
5. Foundations.
6. Ground rods and clamps.
7. Guards.
8. Insulator pins and suspension bolts.
9. Pole steps.
10. Poles, wood, steel, concrete or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving.

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15. Painting.
16. Roofing.
17. Stencilling.
18. Tagging.
19. Transformers racks and platforms.
20. Other fixtures.

1625-304 Brushing (OL = 50 years)

This account shall include the costs associated with brushing of the distribution system.

1625-305 Survey Costs (OL = 35 years)

This account shall include the costs associated with land surveys, assessments, management and easements.

1625-401 Overhead Conductors (OL = 50 years)

This account shall include the installation costs of overhead conductors and accessories used for distribution purposes. Components of cost:

1. Armour rods, connectors, hot line clamps and compressor fittings.
2. Brackets.
3. Circuit breakers (Pole mounted).
4. Conductors, including insulated and bare wires and cables.
5. Connectors.
6. Ground wires.
7. Splices.
8. Switches.
9. Tie wire and clamps.
10. Other line accessories.
11. Insulators.

1625-410 Overhead Services (OL = 40 years)

This account shall include the installation and maintenance costs of overhead services such as transmission line installation and upgrades.

1625-501 Underground Conduit (OL = 40 years)

This account shall include the installation costs of underground conduit devices and tunnels used for distribution purposes.

Note: The cost of ditching is to be included in this account when associated with the cable which is directly buried.

Components of cost:

1. Conduit, concrete, brick and tile, including iron pipe, Murray duct and standpipe on poles.
2. Excavation, including shoring, bracing, backfill, trenching and

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- disposal of excess excavated material.
3. Foundations and setting specially constructed for and not expected to outlast the apparatus for which constructed, including pad mount equipment.
 4. Ground rods and ground wire.
 5. Insulators.
 6. Lateral conduits.
 7. Lighting systems.
 8. Manholes, concrete or brick, including iron or steel frames and covers, pathways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
 9. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
 10. Planking.
 11. Protection of street openings.
 12. Removal and relocation of subsurface obstructions.
 13. Sewer connections, including drains, traps, tide valves, check valves, etc.
 14. Sumps, including pumps.
 15. Vaults for transformers and equipment.
 16. Ventilating equipment.

1625-510 Underground Services (OL = 40 years)

This account shall include the installation costs of underground conductors and services. Components of Cost:

1. Cables, wire, armoured conductors buried or submarine, including insulating materials, splices in terminal chamber, potheads, termination, etc.
2. Circuit breakers.
3. Fireproofing in connection with any item installed herein.
4. Hollow core, oil filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.
5. Lead and fabric covered conductors, compound filled, oil filled or vacuum splices, potheads.
6. Racking of cables.
7. Service pedestals.
8. Switches.
9. Other line devices.

1625-610 Meters (OL = 16 years)

This account shall include the cost of meters purchased and used in measuring electricity delivered to its users whether actually in service or held in reserve. Components of cost:

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1. Alternating current watt-hour meters.
2. Demand meters.
3. Graphic demand meters.
4. Maximum demand meters.
5. Digital pulse recorders.

Note: This account shall not include meters for recording output of a generating station, substation, etc. It includes only meters used to record energy delivered to customers.

1625-620 Meter Equipment (OL = 16 years)

This account shall include the installation costs of metering devices and appurtenances thereto used to transform electricity so that it can be measured by meter when delivered to its users. Components of cost:

1. Installation, labour of (first installation only)
2. Instrument transformers.
3. Meters boards, boxes, tanks, fittings and connectors.
4. Meter switches, cut-outs and test switches.
5. Potential transformer fuses.
6. Protective devices.
7. Service entrance cable and caps.
8. Multi breakers.
9. Grounding materials.

1625-710 Substation Equipment (OL = 40 years)

This account shall include the installation costs of substation equipment including transformers, etc. which are used for the purpose of changing the characteristics of electricity in connection with distribution.

Components of cost:

1. Bus compartments, concrete, brick and sectional steel, including items permanently attached thereto.
2. Conduit, including concrete and iron duct runs not part of building.
3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards and connections.
4. Conversion equipment, indoor and outdoor, frequency changers, motor generator sets, rectifiers, synchronous converters, motors, cooling equipment and associated connections.
5. Fixed and synchronous condensers, including transformers, switching equipment, blowers, motors and connections.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment, etc.,
8. Ground rods and ground wires for grounding network.
9. Platforms, railings, steps, gratings and appurtenances, apparatus tested herein.

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10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lighting arrestors, cable and wire runs from and to outdoor connections or to manholes and the associated regulators, reactors, resistors, surge arrestors and associated equipment.
11. Switchboards, including meters, relays, control wiring, etc.
12. Switching equipment indoor and outdoor, including all of the circuit breakers and operating mechanisms, truck switches and disconnect switches.
13. Tools and appliances.
14. Towers, steel structures, poles and appurtenant fixtures used for supporting substation equipment and buses.
15. Transformers.

1625-720 Substation Buildings (OL = 55 years)

This account shall include the costs associated with buildings located at the distribution substation site.

1625-730 Substation Fences (OL = 30 years)

This account shall include the fences surrounding the distribution substation site.

1625-760 IPP Substation (OL = 25 years)

This account shall include all costs associated with IPP (Independent Power Producer) substations. This account is setup with 25 year operating life as the IPPs have 25 year EPA (Electricity Purchase Agreements) with YEC.

1625-815 Street Lights (OL = 40 years)

This account shall include the installation costs of equipment used wholly for public street and highway lighting or traffic, fire alarm, police and other signal systems. Components of cost:

1. Armoured conductors, buried or submarine, including insulators, insulating materials, splices, trenching, etc.
2. Automatic control equipment.
3. Ballasts, conductors, overhead or underground, including lead or fabric covered parkway cables, splices, insulators, etc.
4. Lamps, arc, incandescent, mercury vapour or other types, including glassware, suspension fixtures, brackets, etc. municipal inspection, ornamental lamp standards.
5. Pavements disturbed, including cutting and replacing pavement, pavement base and sidewalks.
6. Permits

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7. Poles, wood, concrete or steel, used exclusively for street lighting.
8. Protection of street openings.
9. Relays, electric eyes and time clocks.
10. Switches.
11. Transformers, pole mounted or underground, used exclusively for street lighting.

1625-905 Line Transformers (OL = 35 years)

This account shall include the installation costs of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is to be used by the customer, whether actually in service or held in reserve. Components of cost:

1. Installation, labour of (first installation only).
2. Switches forming part of a transformer unit.
3. Transformer cut out boxes (fuse cut outs)
4. Lightning arrestors.
5. Transformers, line and network.
6. Capacitors.
7. Network protectors.

1625-921 Capacitor Installations (OL = NA)

This account shall include the costs associated with capacitor installations on distribution lines.

1625-961 Sentinel Lights (OL = 30 years)

This account shall include the installation costs of sentinel and flood lighting (other than street lighting for municipalities and highways), for which customers are charged a flat rate. Components of cost:

1. Brackets, complete with fixture and ballast.
2. Poles, wood, steel or concrete.
3. Electric eye and relays.
4. Conductors, overhead and underground.

GL Code

0000-000-1630 WIND TURBINE

Class ID

1630-400 Wind Turbine (OL = 30 years)

This account shall include the costs associated with the wind turbines and wind monitoring equipment, including blade upgrades and heaters

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GL Code

0000-000-1635 MAIN TRANSMISSION FACILITIES

Class ID

1635-300 Poles and Fixtures (OL = 65 years)

This account shall include the installation costs of poles and fixtures used for transmission purposes. Components of cost:

1. Anchors, head arm and other including guy guards, guy clamps, strain plates and strain insulators.
2. Brackets
3. Cross arms and braces.
4. Excavations, backfill, etc.
5. Extension arms.
6. Foundation.
7. Gaining, roofing, stencilling and tagging.
8. Ground rods and clamps.
9. Guards.
10. Insulator pins and guys, suspension bolts.
11. Paving.
12. Pole steps.
13. Poles – wood, steel, concrete, or other material.
14. Racks, c/w insulators.
15. Railings, etc.
16. Reinforcing and stubbing.
17. Setting.
18. Shaving and painting.
19. Timbers.
20. Vibration dampers.

1635-304 Brushing (OL = 60 years)

This account shall include the costs of brushing associated with the main transmission lines and facilities.

1635-305 Survey Costs (OL = 60 years)

This account shall include the land survey costs associated with the main transmission facilities.

1635-340 Brushing Poles (OL = NA)

1635-402 Overhead Conductors/Poles (OL = 60 years)

This account shall include the installation costs of overhead conductors

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used for transmission purposes. Components of cost:

1. Circuit breakers not in substations.
2. Conductors, including insulators and bare wires.
3. Lighting arrestors.
4. Switches.
5. Other line devices and cables.
6. Conductor clamps, insulators, including pin suspension and other types.

1635-404 Overhead Conductors/Towers (OL = 60 years)

This account shall include the installation costs of overhead conductors used for transmission purposes. Components of cost:

1. Circuit breakers not in substations.
2. Conductors including insulators and bare wires
3. Lightning arrestors.
4. Switches.
5. Other Line devices and cables.
6. Conductor clamps, insulators, including pin suspension and other types.

1635-509 Towers and Fixtures (OL = NA)

This account shall include the installation costs of towers and fixtures used for transmission purposes. Components of cost:

1. Anchors, head arm and other including guy guards, guy clamps, strain plates and strain insulators.
2. Brackets.
3. Cross arms and braces.
4. Excavations, backfill, etc.
5. Extension arms.
6. Foundation.
7. Gaining, roofing, stencilling and tagging.
8. Ground rods and clamps.
9. Guards.
10. Insulator pins and guys, suspension bolts.
11. Paving.
12. Racks, c/w insulators.
13. Railings, etc.
14. Reinforcing and stubbing.
15. Setting
16. Shaving and painting.
17. Timbers.
18. Towers.

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19. Vibration dampers.

1635-710 Substation Equipment (OL = 54 years)

This account shall include the installation costs of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with transmission or controlling transmission circuits. Components of cost:

1. Bus compartments, concrete brick and sectional steel including items permanently attached thereto.
2. Conduit, including concrete and duct runs not a part of a building.
3. Control equipment, including batteries, battery charging equipment, transformers, remote relay boards and connections.
4. Conversion equipment, including transformers, indoors and outdoors, frequency changes, motor generator sets, rectifiers, synchronous converters, motors, cooling and equipment and associated connections.
5. Fixed and synchronous condensers, including transformers switching equipment, HV circuit breakers, blowers, motors and connections.
6. Foundations and settings; specially constructed for and not expected to outlast the apparatus for which provided.
7. General station equipment, including air compressors, motors, hoists, cranes, test equipment, ventilating equipment.
8. Ground rods and ground wire for ground network.
9. Platforms, railings, steps, gratings and appurtenances to apparatus listed herein.
10. Primary and secondary voltage connections, including bus runs and supports, insulators, potheads, lightning arrestors, cable and wire runs from and to outdoor connections or to man holes and the associated regulators, reactors, resistors, surge arrestors and accessory equipment.
11. Switchboards, including meters, relays, control wiring, etc.

1635-720 Substation Buildings (OL = 55 years)

This account shall include the costs associated with substation buildings.

1635-730 Substation Fences (OL = 30 years)

This account shall include the costs associated with substation fences.

GL Code

0000-000-1640 SUB TRANSMISSION LINES

Class ID

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1640-300 Poles and Fixtures (OL = 65 years)

This account shall include the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire.

Note: materials used for substations, including transformers, will be charged to account 1640-710 Substation Equipment.

Components of cost:

1. Anchors, head arm and other guys, including any guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Cross arms and braces.
4. Extension arms.
5. Foundations.
6. Ground rods and clamps.
7. Guards.
8. Insulator pins and suspension bolts.
9. Pole steps.
10. Poles, wood, steel, concrete or other material.
11. Racks complete with insulators.
12. Reinforcing and stubbing.
13. Settings.
14. Shaving.
15. Painting.
16. Roofing.
17. Stencilling.
18. Tagging.
19. Transformers racks and platforms.
20. Other fixtures.

1640-301 Poles & Fixtures Minto Mines (OL = 12 years)

This account shall include the installation costs of poles and fixtures at Minto Mine.

1640-304 Brushing (OL = 60 years)

This account shall include the costs of brushing associated with sub transmission lines.

1640-305 Survey Costs (OL = 60 years)

This account shall include the land survey costs associated with the sub transmission lines.

1640-306 Brushing Minto Mine (OL = 12 years)

This account shall include the costs of brushing associated with sub transmission lines at Minto Mine.

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1640-307 Survey Costs Minto Mine (OL = 12 years)

This account shall include the land survey costs associated with the sub transmission lines at Minto Mine.

1640-401 Overhead Conductors (OL = 60 years)

This account shall include the installation costs of overhead conductors and accessories used for distribution purposes. Components of cost:

1. Armour rods, connectors, hot line clamps and compressor fittings.
2. Brackets.
3. Circuit breakers (Pole mounted).
4. Conductors, including insulated and bare wires and cables.
5. Connectors.
6. Ground wires.
7. Splices.
8. Switches.
9. Tie wire and clamps.
10. Other line accessories.
11. Insulators.

1640-405 Underground Conductors/Conduit (OL = 45 years)

This account shall include the installation costs of underground conduit devices and tunnels used for distribution purposes. Note: The cost of ditching is to be included in this account when associated with the cable which is directly buried. Components of cost:

1. Conduit, concrete, brick and tile, including iron pipe, murray duct and standpipe on poles.
2. Excavation, including shoring, bracing, backfill, trenching and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed, including pad mount equipment.
4. Ground rods and ground wire.
5. Insulators.
6. Lateral conduits.
7. Lighting systems.
8. Manholes, concrete or brick, including iron or steel frames and covers, pathways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
9. Pavement disturbed, including cutting and replacing pavement, pavement base and sidewalks.
10. Planking.
11. Protection of street openings.
12. Removal and relocation of subsurface obstructions.
13. Sewer connections, including drains, traps, tide valves, check valves, etc.

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- 14. Sumps, including pumps.
- 15. Vaults for transformers and equipment.
- 16. Ventilating equipment

- 1640-407 Overhead Conductors Minto Mine (OL = 12 years)**
This account shall include the installation cost of overhead conductors at Minto Mine.
- 1640-710 Substation Equipment (OL = 54 years)**
This account shall include costs associated with substation equipment.
- 1640-711 Substation Equipment Minto Mine (OL = 12 years)**
This account shall include costs associated with substation equipment and upgrades at Minto Mine.
- 1640-921 Capacitor Installations (OL = NA)**
This account shall include the costs of capacitor installations on sub transmission lines.

GL Code

0000-000-1645 BUILDING AND OTHER EQUIPMENT

Class ID

- 1645-106 Land Rights (OL = NA)**
This account shall include costs associated with land rights of the general plant.
- 1645-110 Survey Costs Land (OL = 50 years)**
This account shall include costs associated with land survey of the general plant.
- 1645-200 Structures and improvement hydro (OL = 50 years)**
This account shall include costs of improvements associated with a hydro facility that is not attached to the hydro plant itself. These improvements are much more general and have a shorter expected life than those allocated to the code 1615-200 (Hydro – Structures and improvements). This would include renovations and improvements to berms, signage, roads, boilers, and fall arrest.
- 1645-201 Building and Improvements (OL = 55 years)**
This account shall include costs associated with buildings and improvements. This would include staff housing, warehouses, offices,

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fencing, building envelopes, fish hatchery, yard work, guard rails.

1645-202 Office Furniture & Equip (OL = 20 years)

This account shall include the cost of office furniture and equipment owned by the utility and devoted to utility service and not permanently attached to buildings, except the cost of such furniture and equipment which the utility elects to assign to other plant accounts on a functional basis. Components of cost:

1. Bookcases and shelves.
2. Desks, chairs and desk equipment.
3. Drafting room equipment.
4. Filing, storage and other cabinets.
5. Floor coverings.
6. Library and library equipment.
7. Mechanical office equipment, such as accounting machines and typewriters, adding machines, calculators.
8. Safes
9. Tables.

1645-210 Communication Site Towers (OL = 40 years)

This account shall include costs of communication site towers associated with general plant.

1645-220 Communication Site Fences (OL = 30 years)

This account shall include costs of communication site fences associated with general plant.

1645-310 Main Frame Computer (APL Share) (OL = NA)

This account shall include the 1/3 cost of mainframe computer equipment and installation cost which is jointly owned by APL, NUL and CWNG. Components of cost:

1. Mainframe equipments (AMDAHL)

1645-320 Computer Hardware (OL = 7 years)

This account shall include the full cost of computer equipment (other than mainframe), which is owned by APL. Components of cost:

1. Personal computers and associated equipment.
2. Printers (Mainframe and PC)
3. Terminals.
4. Word processors and associated equipment.
5. Keyboards
6. DASD (Direct Access Storage Device)

1645-330 Computer Software (OL = 5 years)

Yukon Energy Corporation

GP Users Manual for Property Plant and Equipment

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This account shall include the cost of computer software purchases, including upgrades, enhancements and maintenance.

***Note: Now goes to account 2120 – intangibles**

1645-340 CUL Hardware (OL = NA)

1645-505 Tools and Instruments (OL = 20 years)

This account shall include the cost of tools, implements and equipment used on construction, repair work, general shops and garages and the installation costs of laboratory equipment used for general laboratory purposes and not specifically provided for or includable in other accounts.

Components of cost:

1. Air compressors
2. Automobile repair shop equipment.
3. Cable pulling equipment
4. Electric equipment.
5. Gasoline pumps, oil pumps and storage tanks.
6. Greasing tools and equipment, hoists.
7. Ladders.
8. Lathes.
9. Machine tools
10. Motor drive tools.
11. Pipe threading and cutting tools.
12. Pneumatic tools
13. Pumps
14. Work Benches.
15. Ammeters.
16. Frequency changers.
17. Galvanometers.
18. Induct meters.
19. Laboratory standard mille-volt meters.
20. Laboratory standard voltmeters.
21. Meter testing equipment.
22. Motor generator sets
23. Panels
24. Phantom loads.
25. Portable graphic ammeters, voltmeters and wattmeters.
26. Potentiometers.
27. Rotating standards.
28. Standard call, reactance resistor and shunt.
29. Switchboards.
30. Synchronous timers.
31. Testing panels.
32. Transformers.
33. Voltmeters.

Yukon Energy Corporation

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- 1645-507 Wind Monitoring Equipment (OL = 15 years)**
This account shall include costs associated with wind monitoring equipment. This includes tall towers and ultrasonic anemometers.
- 1645-605 Communication Equipment (OL = 20 years)**
This account shall include the installation costs of telephone, fibre optic and wireless equipment for general use in connection with utility operations. Components of cost:
1. Antennae
 2. Booths
 3. Cables
 4. Distribution boards
 5. Handsets, manual and dial
 6. Insulators
 7. Intercommunicating sets
 8. Loading coil
 9. Poles and fixtures used wholly for telephone or fibre optics.
 10. Radio transmitting and receiving sets.
 11. Remote control equipment and lines
 12. Sending Keys
 13. Storage batteries.
 14. Switchboards
 15. Testing instruments
 16. Underground conduit and cable used wholly for telephone or fibre optics.
 17. Touch tone encoders.
- 1645-701 Training Development Costs (OL = 10)**
This account shall include the costs associated with training development.
- 1645-810 Company Owned Houses/Land (OL = 40 years)**
This account shall include the costs of upgrades and maintenance associated with the land of houses owned by the company.
- 1645-820 Company Owned Houses/Buildings (OL = 40 years)**
This account shall include the costs of upgrades and maintenance associated with the buildings of houses owned by the company.
- 1645-850 AMP Project (OL = 10 years)**
This account shall include the costs associated with the AMP financial system implementation and upgrades.

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0000-000-1650 TRANSPORTATION

Class ID

- 1650-406 Transportation Depreciation**
This account is for accumulated depreciation prior to implementation of FIS in June 1993.
- 1650-411 Utility Vehicles (OL = 8 years)**
This account shall include the costs of utility vehicle purchases. These include utility trailers, cargo trailers, atvs, snowmobiles, and boats.
- 1650-412 Sedans and Station wagons (OL = 11 years)**
This account shall include the costs of vans, cars and smaller vehicles that don't fit the category 1650-440 - Trucks under $\frac{3}{4}$ tons.
- 1650-420 Trucks and Pole Trailers (OL = 25 years)**
This account shall include the costs of large trucks that pull pole trailers and small pole trailers < 10,000 lbs.
- 1650-430 Pole Trailers > 10,000 lbs. (OL = 25 years)**
This account shall include the costs of pole trailers larger than 10,000 lbs.
- 1650-440 Trucks $\frac{3}{4}$ to 2 ton (OL = 9 years)**
This account shall include the costs of trucks $\frac{3}{4}$ ton to 2 tonnes used by the employees to carry out day to day duties.
- 1650-450 Trucks >2 ton and < 3 ton (OL = NA)**
This account shall include the costs of trucks more than 2 tonnes but less than 3 tonnes used by the employees to carry out day to day duties.
- 1650-460 Pole Cats (OL = NA)**
- 1650-470 Trucks > 3 ton (OL = 25 years)**
This account shall include the costs of trucks more than 3 tonnes including diggers, crane trucks, forklifts and bucket trucks.
- 1650-480 Tractor (OL = NA)**
- 1650-490 Foremost (OL = 20 years)**
This account shall include the costs of large specialty vehicles which are usually tracked (rather than wheeled).

GL Code

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0000-000-1655 Critical Spares

Class ID

1655-750 Critical Spares (OL = 00 years)

This account shall include repair/replacement parts for units that are critical to keep in working order. These parts may have a long lead time or be difficult to source. This class is not depreciated as these parts are not yet in use.

GL Code

0000-000-1665 Gas Production

Class ID

1665-200 Structures and improvements (OL = 72 years)

The accounts for structures and improvements shall include the cost of all buildings and facilities to house, support, or safeguard property or persons, including all fixtures permanently attached to and made a part of buildings and which cannot be removed therefrom without cutting into the walls, ceilings, floors, or without in some way impairing the buildings, and improvements of a permanent character on or to land. Also include those costs incurred in connection with the first clearing and grading of land and rights-of-way and the damage costs associated with construction and installation of plant.

The cost of specially provided foundations not intended to outlast the machinery or apparatus for which provided, and the cost of angle irons, castings, etc., installed at the base of an item of equipment, shall be charged to the same account as the cost of the machinery, apparatus, or equipment.

The items of cost to be included in the accounts for structures and improvements are as follows:

1. Architects' plans and specifications including supervision.
2. Boilers, furnaces, piping, wiring, fixtures, and machinery for heating, lighting, signalling, ventilating, and air-conditioning systems, plumbing, vacuum cleaning systems, incinerator and smoke pipe, flues, etc.
3. Fire protection systems when forming a part of a structure.
4. Foundations and piers for machinery, constructed as a permanent part of a building or other item listed herein.
5. Grading and clearing when directly occasioned by the building of a structure.
6. Landscaping, lawns, shrubbery, etc.
7. Permanent paving, concrete, brick, flagstone, asphalt, etc., within the

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property lines.

8. Sump pumps and pits
9. Yard drainage system
10. Yard lighting system
11. Yard surfacing, gravel, concrete, or oil. (First cost only.)

1665-403 Fuel holders, producers and accessories (OL = 60 years)

This account shall include the cost installed of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe through which fuel is directly drawn to the engine, also the cost of gas producers and accessories devoted to the production of gas for use in prime movers driving main electric generators. Items of cost include:

1. Blower and fans.
2. Boilers and pumps.
3. Economizers.
4. Exhauster outfits.
5. Flues and piping.
6. Pipe system.
7. Producers.
8. Regenerators.
9. Scrubbers.
10. Steam injectors.
11. Tanks for storage of oil, gasoline, etc.
12. Vaporizers.

1665-500 Generating Equipment and Prime movers (OL = 40 years)

This account shall include the cost installed of other prime movers devoted to the generation of electric energy, together with their auxiliaries. Items of cost include:

1. Air-filtering system.
2. Belting, shafting, pulleys, reduction gearing, etc.
3. Cooling system, including towers, pumps, tanks, and piping.
4. Cranes, hoists, etc., including items wholly identified with apparatus listed herein.
5. Engines, gasoline, gas, or other internal combustion.
6. Foundations and settings specially constructed for and not expected to outlast the apparatus for which provided.
7. Governors.
8. Ignition system.
9. Inlet valve.
10. Lighting systems.
11. Lubricating systems, including filters, tanks, pumps, and piping.
12. Mechanical meters, including gauges, recording instruments, sampling, and testing equipment.

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13. Mufflers.
14. Piping.
15. Starting systems, compressed air, or other, including compressors and drives, tanks, piping, motors, boards and connections, storage tanks, etc.
16. Steelwork, specially constructed for apparatus listed herein.
17. Waste heat boilers, antifluators, etc.

1665-503 Gas Plant Overhaul (OL = 10 years)

1665-504 Gas Engine Overhaul (OL = 2 years)

1665-508 Generators (OL = NA)

This account shall include the cost installed of power driven main generators. Items of cost include:

1. Cranes, hoists, etc., including items wholly identified with such apparatus.
2. Fire-extinguishing equipment.
3. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
4. Generator cooling system, including air cooling and washing apparatus, air fans and accessories, air ducts, etc.
5. Generators—main, a.c. or d.c., including field rheostats and connections for self-excited units and excitation system when identified with the generating unit.
6. Lighting systems.
7. Lubricating system, including tanks, filters, strainers, pumps, piping, coolers, etc.
8. Mechanical meters, and recording instruments.
9. Platforms, railings, steps, gratings, etc., appurtenant to apparatus listed herein.

NOTE: If prime movers and generators are so integrated that it is not practical to classify them separately, the entire unit may be included in account 1665-508, Generators.

1665-600 Accessory electric equipment (OL = 45 years)

This account shall include the cost installed of auxiliary generating apparatus, conversion equipment, and equipment used primarily in connection with the control and switching of electric energy produced in other power generating stations, and the protection of electric circuits and equipment, except electric motors used to drive equipment included in other accounts. Such motors shall be included in the account in which the equipment with which it is associated is included. Items of cost include:

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1. Auxiliary generators, including boards, compartments, switching equipment, control equipment, and connections to auxiliary power bus.
2. Excitation system, including motor, turbine and dual-drive exciter sets and rheostats, storage batteries and charging equipment, circuit breakers, panels and accessories, knife switches and accessories, surge arresters, instrument shunts, conductors and conduit, special supports for conduit, generator field and exciter switch panels, exciter bus tie panels, generator and exciter rheostats, etc., special housings, protective screens, etc.
3. Generator main connections, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, current transformers, potential transformers, protective relays, isolated panels and equipment, conductors and conduit, special supports for generator main leads, grounding switch, etc., special housing, protective screens, etc.
4. Station control system, including station switchboards with panel wiring, panels with instruments and control equipment only, panels with switching equipment mounted or mechanically connected, trunk type boards complete, cubicles, station supervisory control boards, generator and exciter signal stands, temperature-recording devices, frequency control equipment, master clocks, watt-hour meter, station totalizing wattmeter, storage batteries, panels and charging sets, instrument transformers for supervisory metering, conductors and conduit, special supports for conduit, switchboards, batteries, special housing for batteries, protective screens, doors, etc.
5. Station buses, including main, auxiliary transfer, synchronizing and fault ground buses, including oil circuit breakers and accessories, disconnecting switches and accessories, operating mechanisms and interlocks, reactors and accessories, voltage regulators and accessories, compensators, resistors, starting transformers, current transformers, potential transformers, protective relays, storage batteries and charging equipment, isolated panels and equipment, conductors and conduit, special supports, special housings, concrete pads, general station ground system, special fire-extinguishing system, and test equipment.

NOTE A: Do not include in this account transformers and other equipment used for changing the voltage or frequency of electric energy for the purpose of transmission or distribution.

NOTE B: When any item of equipment listed herein is used wholly to furnish power to equipment included in another account, its cost shall be included in such other account.

1665-700 Miscellaneous power plant equipment (OL = 30 years)

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This account shall include the cost installed of miscellaneous equipment in and about the other power generating plant, devoted to general station use, and not properly includible in any of the foregoing other power production accounts. Items of cost include:

1. Compressed air and vacuum cleaning systems, including tanks, compressors, exhausters, air filters, piping, etc.
2. Cranes and hoisting equipment, including cranes, cars, crane rails, monorails, hoists, etc., with electric and mechanical connections.
3. Fire-extinguishing equipment for general station use.
4. Foundations and settings, specially constructed for and not expected to outlast the apparatus for which provided.
5. Miscellaneous equipment, including atmospheric and weather indicating devices, intrasite communication equipment, laboratory equipment, signal systems, callophones, emergency whistles and sirens, fire alarms, and other similar equipment.
6. Miscellaneous belts, pulleys, countershafts, etc.
7. Refrigerating system including compressors, pumps, cooling coils, etc.
8. Station maintenance equipment, including lathes, shapers, planers, drill presses, hydraulic presses, grinders, etc., with motors, shafting, hangers, pulleys, etc.
9. Ventilating equipment, including items wholly identified with apparatus listed herein.

NOTE: When any item of equipment, listed herein is used wholly in connection with equipment included in another account, its cost shall be included in such other account.

1665-730 Fencing (OL = 30 years)

This account includes the cost of fences surrounding the site. This fencing is not chain link fence but rather a corrugated metal fence. This is a solid fence built to prevent vapour dispersion.

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0000-000-1910 to 1944 CONTRIBUTIONS

GL Code

0000-000-1910

Residential Contributions (OL = 40 years)

Contribution in aid of construction for residential properties.

Class ID

1910-910

GL Code

0000-000-1912

General Service Contributions (OL = 40 years)

Contribution in aid of construction for general services properties.

Class ID

1912-920

GL Code

0000-000-1914

Industrial Contributions (OL = 40 years)

Contribution in aid of construction for industrial properties.

Class ID

1914-930

GL Code

0000-000-1916

Street & Sentinel Lights Contributions (OL = 30 years)

Contribution in aid of construction for street and sentinel installations.

Class ID

1916-960

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GL Code**0000-000-1918****Other Contributions**

Contribution in aid of construction for other properties

Class ID

1918-990

Contributions – Other

1918-992

Contributions - IPP (OL = 25 Years)

GL Code**0000-000-1930****Minto Explr CC 138Kv Contributions (OL = 56 years)**Class ID

1930-935

GL Code**0000-000-1932****Minto Spur 25kv Contributions (OL = 12 years)**Class ID

1932-940

GL Code**0000-000-1940****YDC Contributions (OL = 30 to 81 years)**Class ID

1940-995

GL Code**0000-000-1942****YTG Contributions (OL = 35 to 56 years)**Class ID

1942-996

GL Code**0000-000-1944****GIF Contributions OL = 55 to 81 years)**Class ID

1944-997

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Net Differences

Net Difference depreciation amounts are not kept in the fixed asset subledger. The amounts in these accounts are kept in a spreadsheet and the entries to the accounts are made once a month.

0000-000-1611	LAND DIFFERENCES
0000-000-1711	Land Differences Accum Depr
0000-000-1616	HYDRO PLANT DIFFERENCES
0000-000-1716	Hydro Plant Differences Accum Depr
0000-000-1621	DIESEL PLANT DIFFERENCES
0000-000-1721	Diesel Plant Differences Accum Depr
0000-000-1626	DISTRIBUTION SYSTEMS DIFFERENCES
0000-000-1726	Distribution Differences Accum Depr
0000-000-1631	WIND TURBINE DIFFERENCES
0000-000-1731	Wind Turbine Differences Accum Depr

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0000-000-1636	MAIN TRANSMISSION DIFFERENCES
0000-000-1736	Main Transmission Differences Accum Depr
0000-000-1641	SUB TRANSMISSION DIFFERENCES
0000-000-1741	Sub Transmission Differences Accum Depr
0000-000-1646	BUILDINGS & EQUIPMENT DIFFERENCES
0000-000-1746	Bldngs & Equip Differences Accum Depr
0000-000-1651	TRANSPORTATION DIFFERENCES
0000-000-1751	Transportation Differences Accum Depr

Accumulated Depreciation

Depreciation is calculated in the subledger by asset within the Class ID. The depreciation amount is then pushed forward to the GL through the GL code. There are several class ID's that point to each accumulated depreciation account in the GL code.

GL Code

0000-000-1710 LAND ACCUM DEPR

Class ID

1610-003 Land Hydro Production

1610-004 Land Diesel Production

1610-006 Land Main Trx Facilities

1610-008 Land Distribution System

1610-009 Land General Plant

1610-106 Land Rights

1610-110 Land – LNG Production

GL Code

0000-000-1715 HYDRO PLANT ACCUM DEPR

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Class ID

1615-200	Hydro-Strctrs & Imprvmts
1615-205	Hydro-Rsrvoirs Dams & Wtrways
1615-206	Hydro, Dams wtwys Twin Assets
1615-504	Hydro Assets Overhaul
1615-506	Hydro-Wtrwhls, Trbines & Gen's
1615-600	Hydro-Accessory Electric Equip
1615-700	Hydro-Misc Power Plant Equipm
1615-730	Hydro-Fences

GL Code

0000-000-1720 DIESEL PLANT ACCUM DEPR

Class ID

1620-200	Diesel – Strctrs and Imprvmts
1620-201	Diesel - Building & Imprvmnt
1620-403	Diesel - Fuel Hldrs, Prdcts & Accss
1620-500	Diesel – Gnrtnng Equip & Prime
1620-508	Diesel – Minto Gnrtnng Equip
1620-600	Diesel – Acc Electric Equip
1620-700	Diesel – Misc Power Plant Equip

GL Code

0000-000-1725 DISTRIBUTION SYSTEMS ACCUM DEPR

Class ID

1625-300	Dist System – Poles & Fxtrs
1625-304	Dist System - Brushing

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1625-305	Dist System - Survey Costs
1625-401	Dist System – O/H Cndctrs
1625-410	Dist System – O/H Services
1625-501	Underground Conduit
1625-510	Dist System - Undrgrnd Services
1625-550	Dist System – Altrntv Enrgy Eq
1625-610	Dist System - Meters
1625-620	Dist System - Meter Equip
1625-710	Dist System – Sbstn EEquip
1625-720	Dist System - Sbstn Buildings
1625-730	Dist System - Substation Fences
1625-815	Dist System - Street Lights
1625-905	Dist System - Line Transformers
1625-921	Capacitor Installations
1625-961	Dist System - Sentinel Lights

GL Code

0000-000-1730 WIND TURBINE ACCUM DEPR

Class ID

1630-400 Wind Turbine

GL Code

0000-000-1735 MAIN TRANSMISSION ACCUM DEPR

Class ID

1635-300 Main Trx - Poles & Fxtrs

1635-304 Main Trx - Brushing

1635-305 Main Trx - Survey Costs

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1635-340	Brushing Poles
1635-402	Main Trx – O/H Cndctrs/Poles
1635-404	Main Trx – O/H Cndctrs/Towers
1635-509	Towers and Fixtures
1635-710	Main Trx – Sbstn Equip
1635-720	Main Trx – Sbstn Buildings
1635-730	Main Trx – Sbstn Fences

GL Code

0000-000-1740 SUB TRANSMISSION ACCUM DEPR

Class ID

1640-300	Sub Trx - Poles and Fxtrs
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn
1640-304	Sub Trx - Brushing
1640-305	Sub Trx - Survey Costs
1640-306	Sub Trx - Brushing Mnt Mn
1640-307	Sub Trx - Survey Costs Mnt Mn
1640-401	Sub Trx – O/H Cndctrs
1640-405	Sub Trx – Undrgrnd Cndctrs/Cnd
1640-407	Sub Trx – O/H Cndcts Mnt Mn
1640-710	Sub Trx – Sbstn EEquip
1640-711	Sub Trx – Sbstn Equip Mnt Mn
1640-921	Compactor Installations

GL Code

0000-000-1745 BUILDINGS & EQUIPMENT ACCUM DEPR

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Class ID

1645-106	Building & Other - Land Rights
1645-110	Bldg&Otr - Survey Costs Land
1645-200	Bldg&Otr – Strctrs/Imprvmnt Hyd
1645-201	Bldg&Otr – Building & Imprvmnt
1645-202	Bldg&Otr – Office Frntr & Equip
1645-210	Bldg&Otr - Comm Site Towers
1645-220	Bldg&Otr – Comm Site Fences
1645-310	Bldg&Otr – Mn Frm Cmptr (APL)
1645-320	Bldg&Otr - Computer Hardware
1645-330	Bldg&Otr - Computer Software
1645-340	Bldg&Other - CUL Hardware
1645-505	Bldg&Otr - Tools & Instruments
1645-507	Bldg&Otr - Wind Mntrng Equip
1645-605	Bldg&Otr - Comm Equipment
1645-701	Training Development Costs
1645-810	Bldg&Otr - Houses/Land
1645-820	Bldg&Otr - Houses/Buildings
1645-850	Bldg&Otr - AMP Project

GL Code

0000-000-1750 TRANSPORTATION ACCUM DEPR

Class ID

1650-406	Trxptn – Depreciation
1650-411	Trxptn - Utility Vehicles

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1650-412	Trxptn - Sedans and Stn Wagons
1650-420	Trxptn - Trucks and Pole Trailers
1650-430	Trxptn - Pole Trailers > 10,000 lbs.
1650-440	Trxptn - Trucks 3/4 to 2 ton
1650-450	Trxptn - Trucks >2 ton and < 3 ton
1650-460	Trxptn - Pole Cats
1650-470	Trxptn - Trucks > 3 ton
1650-480	Trxptn - Tractor
1650-490	Trxptn - Foremost

GL Code

0000-000-1765 GAS PRODUCTION ACCUM DEPR

Class ID

1665-200	Structures and Improvements
1665-403	Fuel Holders
1665-500	LNG Generator
1665-508	Generators
1665-600	Accessory Electric Equipment
1665-700	Miscellaneous power plant equipment
1665 730	LNG Fence

Fixed Asset Unit Numbers

When a fixed asset is set up it must be assigned a unit number. Having assigned unit numbers will ensure that we know the true cost or how much we have spent on each unit that we own. We cannot set up an asset when it relates to more than one unit number. The cost must be allocated to the unit numbers. There has to be a one to one relationship.

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There is a location within GP to put this number. When you go to the Asset General Information screen there is a little book in the right hand corner. When you click on this a drop down box shows up with an option for Asset User Data. The third box in this field is for the Unit #. The units to be added are shown below.

In Fixed Assets a unique **Unit Number** is assigned to each asset we need to record costs on. Each unit number is unique and can only be used once.

Assigning Unit Numbers

The assignment of unit numbers is not always clear. The project manager will be required to assist Finance with the assignment of numbers.

Naming convention used

For the most part we have tried to split the numbering of assets into three digit designations. For the most part the split is Location (A= Aishihik, W= Whitehorse, D=Dawson), type of asset (D=Diesel, H=Hydro, W=Wind) and Number (1, 2, 3, etc.). Of course there are exceptions to this rule. All line assets start with L and then the remaining digits are the line that it refers to. All houses start with H and the last digit is the location of the house. All substations start with S and then the remaining digits are the substation that it refers to. All distribution lines start with T and the last digits are the distribution that it refers to. Vehicles are named as their unit number only.

We have taken the following approach for certain unit numbers:

AH0 – this includes those assets that relate to the Aishihik building structure. This would include items like elevator, roof, heating, warehouse storage, etc. Items from this category cannot be allocated to any particular hydro unit.

WHQ – this includes all the trailers, all computer hardware and software, SCADA, printers and faxes, chairs, desks, file cabinets, shelving, fridges, appliances, facilities signage, land easement, fall protection

Vehicles – these have been assigned the actual vehicle number.

L355 – these are assets that are either sub transmission assets from Aishihik to Haines Junction or assets that are called Aishihik Distribution System within the fixed asset system.

GME – this is general moveable equipment that cannot be assigned to any particular location. This would include items like chains, jacks, pump, washers, tools, mobile radio equipment

FD0 - this includes those assets that relate to the Faro Diesel building. This would include items like the building, roof, heating, hoists, fuel storage.

DDO – this includes those assets that relate to the Dawson Diesel building. This would include items like the building, roof, heating, hoists, fuel storage

MDO - this includes those assets that relate to the Mayo Diesel building. This would include items like the building, roof, heating, hoists, fuel storage

MHO - this includes those assets that relate to the Mayo Hydro A building. This would include items like the building, roof, heating, hoists, fuel storage

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MBH - this includes those assets that relate to the Mayo Hydro B building. This would include items like the building, roof, heating, hoists, fuel storage

WDO - this includes those assets that relate to the Whitehorse diesel building. This would include items like the building, roof, heating, hoists, fuel storage

Unit Number	Description
AH0	Aishihik Hydro General
AH1	Aishihik Hydro#1
AH2	Aishihik Hydro#2
AH3	Aishihik Hydro #3
AHP	Aishihik Hydro Plant
ALCS	Aishihik Lake Control Structure
CLCS	Canyon Lake Control Structure
DD0	Dawson Diesel Units General
DD1	Dawson Diesel Unit #1
DD2	Dawson Diesel Unit #1
DD3	Dawson Diesel Unit #3
DD4	Dawson Diesel Unit #4 - removed
DD5	Dawson Diesel Unit #5
DDP	Dawson Diesel Plant
DDS	Dawson Distribution including Feeder 1, Feeder 2 & Express Feeder
DM1	Diesel Mobile Unit #1
DHQ	Dawson Office
FD0	Faro Diesel Units General
FD1	Faro Diesel Unit #1
FD2	Faro Diesel Unit #2
FD3	Faro Diesel Unit #3
FD4	Faro Diesel Unit #4
FD5	Faro Diesel Unit #5
FD7	Faro Diesel Unit #7
FFB	Faro Diesel Plant
FDS	Faro Distribution including Feeder 1 and Feeder 2
FHW1	Ferry Hill Wind Monitoring
GME	General Moveable Equipment
H1A	House Aishihik
H4F	House 4 Faro
H5M	House 5 Mayo Block 8
H6D	House 6 Dawson – this looks like 2 houses are on the same title when purchased from Yukon Housing

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Unit Number	Description
H7D	House 7 Dawson – this is the house on 5 th that is used for travelling staff
H8M	House 8 Mayo Lot 1088
H9M	House 9 Mayo Lot 1095
H10M	House 10 Mayo Industrial subdivision
H11M	Bunkhouse Trailer Mayo Lot 1117
IPP	Independent Power Producer Projects
KUL	Kulan Warehouse and Yard
LCS	Lewes Control Structure
LNG	LNG Facilities - Whitehorse
MLCS	Marsh Lake Control Structure
MD0	Mayo Diesel Units General
MD1	Mayo Diesel Unit #1
MD2	Mayo Diesel Unit #2
MD3	Mayo Diesel Unit #3
MDP	Mayo Diesel Plant
MDS	Mayo Distribution
MH1	Mayo Hydro A Unit #1
MH2	Mayo Hydro A Unit #2
MHB1	Mayo Hydro B – Unit#1
MHB2	Mayo Hydro B – Unit#2
MHB	Mayo Hydro B Plant
MBR	Mayo Hydro B Penstock
MHO	Mayo Hydro A Plant
MOW	Mayo Office Warehouse
WDS	Wareham Dam Structure
MSS	Mayo Spillway Structure
MMD	Minto Mine Diesels
SW2	Sumanik Wind Monitoring#2
WD0	Whse Diesel Units General
WD1	Whse Diesel Unit#1
WD2	Whse Diesel Unit#2
WD3	Whse Diesel Unit#3
WD4	Whse Diesel Unit#4
WD5	Whse Diesel Unit#5
WD6	Whse Diesel Unit#6
WD7	Whse Diesel Unit#7
WDP	Whse Diesel Plant
WHDS	Whse Dam Structure
WFH	Whse Fish Hatchery
WFL	Whse Fish Ladder

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Unit Number	Description
WG1	Whitehorse Gas Unit #1
WG2	Whitehorse Gas Unit #2
WG3	Whitehorse Gas Unit #3
WH1	Whse Hydro Unit#1
WH2	Whse Hydro Unit#2
WH3	Whse Hydro Unit#3
WH4	Whse Hydro Unit #4
WHP	Whse Hydro Plant
WHQ	Whse Office Bldg
WW1	Whse Wind Gen#1
WW2	Whse Wind Gen#2
YM3	Whse Mobile unit 3
BCW1	Bear Creek Wind Monitoring#1
DBW1	D Bay Wind Monitor#1
L127	WH4 to Riverside Sub
L150	S150 to Riverside Sub
L151	LNG Plant to S150
L169	Riverside to McIntyre
L170	Takhini to Carmacks
L171	Aishihik to Takhini
L172	TL Riverside to Takhini
L173	TL Carmacks to Minto
L174	Minto to Stewart
L175	Stewart X south to Stewart X north
L176	TL Stewart to Mayo
L177	TL Stewart to Dawson
L178	TL Carmacks to Faro
L248	TL Mayo B Hydro Plant
L250	TL Mayo to Keno City
L254	Minto Spur line
L355	Aishihik Transmission
L356	Ross River Transmission
L453	Mayo Transmission
OCW1	Old Crow Wind Monitor#1
S146	Faro Trx Substation Reactor Sub
S150	Whitehorse Rapids Substation
S151	Whitehorse LNG
S162	Faro Mine Trx Substation
S163	Carmacks substation for 25kv
S164	Takhini Substation
S167	Aishihik Transmission Substnt
S170	McIntyre Creek Substation
S171	Riverdale Substation

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Unit Number	Description
S248	Mayo B substation
S249	Mayo Substation
S250	Callison Substation
S251	StewartX south
S252	Pelly Crossing
S253	Minto Substation
S254	Minto Mine Substation
S255	Carmacks Substation – new substation as of 2010
S256	Stewart X North
S257	Keno Substation
S258	Mcquesten substaton
S870	Faro Trx Substation - Main Sub
S6846	Deep Creek Switch
S7316	Johnson Crossing Distribution
S7572	Ross River Switch
S9550	Haekel Hill switch
ST147	To McGundy Creek distribution
T153	Little Fox distribution
T170B	Braeburn Distribution
T170C	Campbell Highway Distribution
T170L	Little Salmon distribution
T170D	Drury Creek distribution
T171C	Champagne Distribution
T171M	Mendenhall Distribution
T177M	Moose Creek Distribution
T177P	Patridge Creek Distribution
T170SF	South Fox Lake Distribution
T250	Alexco Keno 69kv spur line (7 other taps off L250 all designated as T250)

REFERENCE: YEC 2025-2027 Application, Tab 9 Net Salvage Study, PDF page 522-539; Attachment A1 – Calculation of Traditional Approach to Net Salvage, PDF pages 540-542

ISSUE: Proposed Capitalization Approach - Net Salvage Study

QUESTION:

- a) Referring to YEC's proposed net salvage methodology to capitalize costs of removal for "interim" replacement projects, please respond to the following:
- i. What modifications will YEC make to its business cases to include information on the portion of the project that is related to costs of removal for "interim" replacement projects? As part of the response, please identify all additional information YEC will provide in its business cases and GRAs in order for parties to test the prudence of costs of removal that it proposes will be capitalized and form part of rate base.
 - ii. What issues does YEC foresee with respect to its ability to forecast "interim" costs of removal for replacement projects? Will forecasting these types of costs, from both a timing and quantum perspective, be easier or harder than forecasting the replacement project costs on a stand-alone basis? Please explain.
 - iii. In the future, if the proposed net salvage methodology is approved, will it be necessary for YEC be able to distinguish costs related to "current existing assets" that have no cost of removal component with "future constructed assets" that will include capitalized costs of removal? Please fully explain why or why not, and provide examples supporting YEC's position on this matter.
- b) Please provide detail with respect to how YEC will determine if the costs of removal for an asset retirement, whether terminal or interim, are routine versus non-routine. Please include a list of all decision points and criterion relied on to make this determination.
- c) Please explain if YEC currently tracks actual cost of removal information. If so, will this practice continue if the Board accepts the proposed capitalization approach for net salvage? Please explain fully.
- d) Please explain if the FRSR balance is currently attributable to specific asset accounts or if it is considered a single fund balance.

-
- 1 e) Please explain why an ARO calculation is relevant to YECs proposal with respect
2 to how costs of removal are collected from ratepayers.
3
- 4 f) Does YEC perform an annual ARO calculation? If so, please identify the types
5 assets to which the ARO relates. If available, please provide a copy of YECs most
6 recent ARO calculation and identify the ARO threshold for materiality.
7
- 8 g) Please explain why YEC or Bowman Economic Consulting Inc. takes specific
9 consideration that “the ARO and FRSR are structured to avoid double-counting of
10 the same principles on the balance sheet” given that, typically, recognition of an
11 ARO is for financial accounting purposes and YEC’s FRSR is for regulatory
12 accounting purposes.
13
- 14 h) In what circumstance would YEC or Bowman Economic Consulting Inc. view the
15 following condition would exist: “... a major upcoming terminal retirement is
16 identified or an ARO has been recorded for a material asset, this amount should
17 be increased to reflect this obligation as early as reasonable plans can be
18 developed for the retirement, including timing and cost.”
19
- 20 i) Please explain if there could be an ARO recorded without there being a related
21 major upcoming terminal retirement to be provided for. Alternatively, please
22 explain if there could be a major upcoming terminal retirement to be provided for
23 without the need for an ARO to be recorded.
24
- 25 j) Referring to Attachment A1 – Calculation of Traditional Approach to Net Salvage,
26 please explain, in detail, how the columns headed “Catch-up Amount” and “Annual
27 Provision for Catch-up (2024 Forecast)” were determined. Please ensure an
28 explanation of whether or how the two calculations considered either the age or
29 remaining life of the assets for each of the account numbers or groups of account
30 numbers at issue is provided.

1 **ANSWER:**

2
3 **(a)**

4
5 (i)

6
7 Please see Yukon Energy's response to YUB-YEC-1-65(e). In accordance with IAS 37
8 Provisions, Contingent Liabilities and Contingent Assets, there may be rare situations
9 where an entity is required to record a liability for expected decommissioning costs that
10 may occur in the future. In that situation, the entity would also record an asset in
11 accordance with IAS 16. In those rare situations, Yukon Energy would be required to
12 include in the capital cost of new assets any costs that will need to be incurred for removal
13 of existing assets on the same site.

14
15 (ii)

16
17 The criteria required to be met to capitalize expected decommissioning costs in the future
18 are very strict, therefore, there are only rare situations where the criteria will be met.
19 Specifically, IAS 37 clause 14(c) states that "A provision shall be recognised when a
20 reliable estimate can be made of the amount of the obligation." Determination of a reliable
21 estimate requires an estimate of the cost, the timing of when the cost will be incurred, and
22 a discount rate to convert those future cash flows into present value. Forecasting these
23 types of costs, from both a timing and quantum perspective, will be significantly harder
24 than forecasting the replacement project costs on a stand-alone basis as replacement
25 project costs on a stand-alone basis usually have a much shorter time horizon.

26
27 The Office of the Auditor General of Canada agrees with Yukon Energy that it currently
28 does not have any asset retirement obligations that need to be recorded.

29
30 (iii)

31
32 No. The new assets constructed after the change will have a somewhat higher cost than
33 equivalent assets before the change where removal costs were not included, due to
34 including the cost of removal of any equipment or components being retired. However,
35 this will not require any special accounting or tracking.

1 **(b)**

2
3 Please see YUB-YEC-I-68(a) regarding the correction to labelling the bullets at page 16
4 of Tab 9 supporting documents.

5
6 It is expected that effectively all interim retirements are routine and would be capitalized
7 as part of the replacement asset. It is possible there may be extreme cases that would
8 require an added accrual, though no such examples are anticipated at this time.

9
10 Non-routine terminal retirements would be highly infrequent events, such as the decision
11 to abandon and remove a major transmission or hydro asset. No such retirement has been
12 recorded in the accounts of the 2005 to 2023 period, and none is presently anticipated.
13 Such an event would likely drive a need for material ARO liability reporting, and planning
14 and estimating of removal costs would occur well in advance of the removal activity.

15
16 There is no clear definition of such an event, except that the dollar value would exceed
17 any balance otherwise achieved with the 0.042% annual accrual.

18
19 **(c)**

20
21 Yukon Energy does currently track costs incurred for removal activities, as reported in the
22 Supporting Documents of Tab 9. As noted in the report, this likely represents primarily the
23 costs of terminal retirements. Most costs that YEC's peers consider interim removal costs
24 are likely already included in YEC capital costs of replacement assets.

25
26 In future, this same detail on terminal retirements would continue to be available in the
27 same fashion as today, as part of the FRSR reconciliation.

28
29 **(d)**

30
31 The FRSR balance is tracked in relation to major asset groupings (e.g., hydro, diesel,
32 wind, transmission, etc.)

33
34 **(e)**

35
36 In principle, an ARO and the FRSR are different approaches to reflecting the same future
37 obligation. In the period leading up to a major retirement, without coordination it would be
38 entirely possible for Yukon Energy to be effectively double counting the future obligation

1 if it is reported in both places. For regulatory purposes, Yukon Energy can function with
2 no specific Revenue Requirement line item for ARO accrual, and all customer funding of
3 future removal activities flowing through the FRSR accrual and balances. However, for
4 financial reporting, the ARO would in effect be reporting an offset to the FRSR, such that
5 once the cash is spent on removal, it is only adjusted to one of the two accounts.

6
7 **(f)**
8

9 Yukon Energy performs an annual ARO calculation that is reviewed in detail by the Office
10 of the Auditor General of Canada. All assets are assessed in an ARO assessment but the
11 only asset that met the definition of an ARO is the Energy Storage System Land Lease.
12 This ARO of approximately \$20,000 was calculated as follows:

- 13
14
 - Estimated reclamation costs \$100,000.
 - Estimated life of asset: 50 years.
 - Benchmark discount rate: 3.28%.
17

18 Yukon Energy has not established an internal level of materiality, however, the Office of
19 the Auditor General of Canada determined that an ARO of \$20,000 is immaterial.

20
21 **(g)**
22

23 Yukon Energy is required to report both the FRSR and the ARO on the balance sheet as
24 liabilities for financial reporting purposes. For regulatory reporting purposes, it is possible
25 to avoid addressing the ARO as part of regulatory applications, so long as the FRSR is
26 sufficiently comprehensive. But it is not possible to ignore the ARO nor the FRSR for
27 financial reporting.

28
29 **(h)**
30

31 It is only possible to define extremely hypothetical examples at this time. For example, if
32 a generating station like Mayo or Aishihik reached end-of-life or end-of-licence and it was
33 not economic or permitted by regulators to rebuild or relicence the plant, an ARO might
34 have to be recorded in the years leading up to the retirement, and an FRSR accrual
35 increase would similarly be required.

1 (i)

2
3 Yes, each of these is possible. The tests for an FRSR appropriation and an ARO are
4 different.

5 However, an ARO would not necessarily lead to an FRSR special appropriation unless
6 the retirement was terminal, and was appropriately documented, timely, and the YUB
7 agreed to establish the appropriation. Similarly, a special FRSR appropriation may be
8 advisable for rate reasons even in cases where there was no ARO recorded.

9 (j)

10
11 The Catch-Up Amount is the 2024 Forecast Gross Plant in Service multiplied by the
12 Accumulated Amortization Ratio to Gross Plant, multiplied by the Estimated Average Net
13 Salvage Rate for YEC. It is measuring the amount of net salvage that should be set aside
14 today given the portion of the asset base that is already amortized.

15
16 The annual provision for Catch-up is the Catch-up Amount divided by the Remaining Life
17 for each account.

1 **REFERENCE:** YEC 2025-2027 Application, Tab 9 Net Salvage Study, PDF pages
2 528, 534 and 537
3

4 **ISSUE:** Proposed Capitalization Approach - Net Salvage Study
5

6 **QUOTE:** PDF page 528:

7 The spending on net salvage since 2005 is notably limited, averaging
8 only \$196,000 per year. A review of projects comprising the spending
9 since 2009 (\$3.1 million in total spend) indicates over half (more than
10 \$1.7 million) is related to only three projects – the removal of
11 Whitehorse Wind #1, Whitehorse Wind #2, and the decommissioning
12 of Whitehorse diesel units from service (WD1, WD2, and WD3).

13 ...

14 From the above data, it appears likely that Yukon Energy has
15 approached use of the FRSR with restraint, likely accounting for costs
16 as either capital or O&M, which could have been included in the FRSR
17 based on utility industry practice.

18 PDF page 534:

19 ... For any given asset, the nominal cost of return and depreciation will
20 decrease over time (as the asset is depreciated), and the real cost
21 (especially in the case of load growth) will decline even faster....

22 PDF page 537:

Table 3: Spending in Relation to Gross PPE**FRSR Spending in Relation to Gross PPE**

(\$000s)

	spend/ recover	Gross PPE (including WIP)	Ratio
2005	139	222,116	0.063%
2006	535	226,567	0.236%
2007	(158)	237,646	-0.066%
2008	73	275,268	0.027%
2009	160	297,262	0.054%
2010	243	378,170	0.064%
2011	53	473,168	0.011%
2012	-	495,796	0.000%
2013	40	520,406	0.008%
2014	-	555,552	0.000%
2015	304	577,888	0.053%
2016	8	589,387	0.001%
2017	55	598,756	0.009%
2018	340	615,387	0.055%
2019	1,173	642,291	0.183%
2020	53	667,962	0.008%
2021	-	691,598	0.000%
2022	49	734,073	0.007%
2023	653	796,724	0.082%
	mean		0.042%

Based on an estimated 2024 year-end Gross PPE of \$841.173 million, this would yield an estimated net salvage spending on terminal retirement activities of \$0.352 million.

QUESTION:

- a) Referring to PDF page 528, on what basis does Bowman Economic Consulting Inc. conclude that YEC is “likely accounting for costs as either capital or O&M, which could have been included in the FRSR based on utility industry practice”? In making this assertion, is Bowman Economic Consulting Inc. inferring that YEC

- 1 has acted contrary to any approved accounting policy or procedure with respect to
2 its practices for recording actual costs of removal? Please explain fully.
3
- 4 b) Referring to PDF page 534, please explain how depreciation expense can
5 decrease over time for a given asset.
6
- 7 c) The quote at PDF page 528 implies that the removal costs related to Whitehorse
8 Wind #1, Whitehorse Wind #2, and the decommissioning of Whitehorse diesel
9 units from service (WD1, WD2, and WD3) would be classified as terminal
10 retirements. Including these three projects, and referring to Table 3 at PDF page
11 537, please identify all capital project(s) attributable to the costs of removal for the
12 years 2006, 2015, 2018, 2019, and 2023, and identify the types of assets that were
13 retired from service. Would the asset retirements have been classified as terminal
14 or interim asset retirements?
15
- 16 d) Referring to PDF page 537 and Table 3: Spending in Relation to Gross property,
17 plant and equipment (PPE), with respect to the implementation of a net salvage
18 accrual rate each year, will this calculation be determined solely on actual costs of
19 removal and actual in-service PPE data?
20
- 21 e) Referring to PDF page 537, in a GRA, will the net salvage accrual rate be applied
22 to test year forecast gross PPE? If it does and the Board does not approve YEC's
23 test year forecast gross PPE, please confirm whether YEC would recalculate the
24 net salvage accrual in the related compliance filing.
25
- 26 f) Please confirm the FRSR is treated as no-cost capital.
27
- 28 g) If the Board were to approve the proposed net salvage methodology, please clarify
29 if the FRSR would be a single pool of funds, or would the funds be attributable to
30 various asset accounts.
31
- 32 h) If the response to part (g) indicates a single pool of funds, how will YEC monitor
33 the net book value for an individual asset account where assets removed from
34 service would show a negative net book value account balance due to an unfunded
35 cost of removal amount? In other words, how will YEC know if it has under
36 recovered or over recovered all costs of removal associated with an asset removed
37 from service if the recovery of those costs is maintained in a single pool of pre-
38 collected costs?

1 **ANSWER:**

2
3 **(a)**

4
5 The basis for concluding Yukon Energy is potentially accounting for costs as either capital
6 or O&M, which could have been included in the FRSR based on utility industry practice,
7 is set out at Table 2 of the Net Salvage report, showing Yukon Energy has recorded far
8 less removal costs (as a percentage of rate base) compared to peers. The conclusion is
9 also supported by the very limited line items recorded as charges against the FRSR, such
10 as shown in (b) of this response, which is far more limited than many peer utilities who
11 record some measure of net salvage for many if not most capital asset replacement jobs.
12

13 No, Yukon Energy has not acted contrary to established or approved accounting policy.
14 One of the issues that arises with respect to the traditional approach to net salvage is that
15 there is considerable discretion as to which expense is incurred to remove an old asset
16 versus to prepare a site and build a new asset. Each utility uses its own discretion to make
17 this determination. For example, if a crew is dispatched to replace a section of poles on a
18 transmission line, many of the costs incurred (mobilization, site preparation, access,
19 demobilization, etc.) are common to the activity of removing the old pole and to adding the
20 new pole. Based on a review of Yukon Energy's recorded FRSR spending compared to
21 peer utilities, it appears Yukon Energy likely elects to record more of the costs as new
22 additions than as removal costs as compared to peers. This has very little net effect on
23 ratepayers, as each approach serves to equally increase rate base.
24

25 One of the benefits of the new approach is the reduction in this discretion.
26

27 **(b)**

28
29 The referenced section is "For any given asset, the nominal cost of return and depreciation
30 will decrease over time (as the asset is depreciated) ...". The reference is noting the
31 combined costs of depreciation and return, not the cost of depreciation alone.
32

33 **(c)**

34
35 Yukon Energy does not have readily available individual project records for 2006.
36

37 For the remainder, the list is as follows:

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-67

2015 expenditures		
WWI work	C15041, will continue to 2016	8,441.73
WAF transmission Upgrades	To remove poles, cross arms, lines of the L170 and L171 (30% of the costs of C15001)	268,673.73
Fish Ladder and Building Improvement	Remove old water holding tank-C13039	<u>26,900.00</u>
2018 Expenditures		
WWI Work	C15041/C18008, Decommission WWI	164,688.09
WAF Transmission Upgrades	Remove old structures L1 70	<u>175,223.67</u>
2019 Expenditures		
WD Decommission	C19010, Decommission of WD1/WD2/WD3	998,999.99
Transmission Upgrades	C19048 L178/L355 Site Restoration	<u>173,970.01</u>
2023 Expenditures		
Offset 2022 Main Trnmssn Projects		- 40,092.90
C22073, WW2 Decommission		549,514.80
C23062 S150 Transformer Disposal (\$96K), Power Pole Replacement (\$46K)		<u>143,277.98</u>

For the above charges, the WAF transmission upgrades, the Fish Ladder and Building Improvement, the Transmission Upgrades and the C23062 S150 disposals are all interim retirements.

(d)

The calculation for 2025-2027 is to use 0.042% as shown. Future updates would use similarly long horizon averages based on actual removal spending (which will only include terminal retirements).

(e)

For rate setting purposes, it would be applied to the forecast Gross PPE, which would be adjusted to reflect YUB decisions.

(f)

The FRSR is treated as an offset to ratebase which is mathematically effectively the same effect as no-cost capital.

(g) and (h)

The FRSR is tracked in relation to broad asset categories (i.e., hydro, diesel, transmission) and it is expected this will continue in future.

1 **REFERENCE:** YEC 2025-2027 Application, Tab 9 Net Salvage Study, PDF page
2 538
3

4 **ISSUE:** Proposed Capitalization Approach - Net Salvage Study
5

6 **QUOTE:** "Implementation of the Capitalization approach would therefore include
7 three separate aspects:

8 **1) Terminal Retirements:** A revision to Yukon Energy's capital asset
9 policy that makes clear that any and all removal costs associated with
10 removal of assets which are being effectively replaced in the same
11 location are part of the capital cost of new assets in that location. If any
12 change is necessary in practice, it should not be a major change, as it
13 appears this is largely consistent with Yukon Energy practice (based on
14 the low rate of charges to the FRSR provision). Also, this approach is
15 routinely cited as being consistent with IFRS (for example, see Altalink
16 AUC proceeding 23848).

17 **2) Routine Interim Retirements:** Maintain the FRSR account as part
18 of regulated ratemaking. Implementation of a new accrual in rates of
19 0.042% of gross PPE each year (approximately \$0.352 million/year) to
20 sustain the account solely related to the estimated requirement for
21 funding the costs of routine terminal retirements.

22 **3) Non-Routine Retirements:** Adoption of a practice that, if needed,
23 any major non-routine terminal retirements are addressed at an early
24 opportunity through accruals in rates. For example, if a major
25 transmission or hydro asset is facing terminal retirement, costs for that
26 activity should be estimated at an early opportunity and an accrual built
27 into rates to build up the balances needed to undertake the removal
28 activity. Note that this would be expected to be very rare (no such event
29 is reflected in the 2005-2023 record)."
30

31 **PREAMBLE:** The text after the bolded headers do not appear to correspond in
32 meaning or intent as noted in the following examples: After item "1)
33 Terminal Retirements" it appears that a proposed policy revision
34 pertaining to costs of removal for "routine interim retirements" is
35 discussed, whereby "all removal costs associated with removal of
36 assets which are being effectively replaced in the same location are
37 part of the capital cost of new assets in that location." The Board

1 understands costs of removal for replacement assets are proposed to
2 be “routine interim retirements.”

3 After item “2) Routine Interim Retirements” it appears that costs of
4 removal for “routine terminal retirements” is discussed, as opposed to
5 routine interim retirements, in relation to the implementation of a new
6 accrual rate of 0.042 per cent. [Emphasis added]

7 After item “3) Non-Routine Retirements” it appears that only major
8 nonroutine terminal retirements are intended to be addressed at an
9 early opportunity through potential net salvage accruals in rates.
10 However, the Board understands that non-routine retirements could
11 potentially be terminal or interim, and the information provided by YEC
12 is not clear, nor are the specifics identified in the heading.

13
14 **QUESTION:**

15
16 a) Please respond to the Board’s comments as provided in the preamble and either
17 correct or further explain YEC’s or Bowman Economic Consulting Inc.’s position
18 with respect to the Board’s observations.

19
20 b) Please complete the following table, indicating within the three columns, where the
21 costs of removal for each of the five types of asset retirements would be recorded:

Type of asset retirement:	Recorded as a capital cost to the replacement asset	Recorded against the FRSR (funded through 0.042 per cent annual accrual)	Recorded against the FRSR (funded through 0.042 per cent annual accrual plus an additional accrual built into rates to build up the balances needed to undertake the removal activity)
	How the costs of removal for each type of asset retirement would be recorded.		
Costs of removal for routine interim retirements			
Costs of removal for non-routine interim retirements			
Costs of removal for routine terminal retirements			
Costs of removal for non-routine terminal retirements			
Other circumstances – please specify and provide example if necessary			

ANSWER:

(a)

The cited headings were inadvertently transcribed. The correct two first bullets are as follows:

1) Interim ~~Terminal~~ Retirements: A revision to Yukon Energy's capital asset policy that makes clear that any and all removal costs associated with removal of assets which are being effectively replaced in the same location are part of the capital cost of new assets in that location. If any change is necessary in practice, it should not be a major change, as it appears this is largely consistent with Yukon Energy practice (based on the low rate of charges to the FRSR provision). Also, this approach is routinely cited as being consistent with IFRS (for example, see Altalink AUC proceeding 23848).

2) Routine Terminal ~~Interim~~ Retirements: Maintain the FRSR account as part of regulated ratemaking. Implementation of a new accrual in rates of 0.042% of gross PPE each year (approximately \$0.352 million/year) to sustain the account solely related to the estimated requirement for funding the costs of routine terminal retirements.

Please see YUB-YEC-1-68 Attachment 1 for the corrected version of the study.

(b)

Please see the table below:

Type of Asset Retirement	Recorded as a capital cost to the replacement asset	Recorded against the FRSR (funded through a 0.042 per cent annual accrual)	Recorded against the FRSR (funded through 0.042 per cent annual accrual plus an additional accrual built into rates to build up the balances needed to undertake the removal activity)
How the costs of removal for each type of asset retirement would be recorded			
Costs of removal for routine interim retirements	Yes		
Costs of removal for non-routine interim retirements	Yes		Possible unforeseen site restoration or salvage activities at a scale that cannot be accommodated within the capital cost of the replacement asset or FRSR accrual. No specific examples identified.
Costs of removal for routine terminal retirements		Yes	
Costs of removal for non-routine terminal retirements			Yes
Other circumstances – please specify and provide examples if necessary		Removal, Site Restoration and Net Salvage activities not tied to an asset replacement or retirement, e.g., clean up of contaminated sites long after any associated asset retirement.	Possible unforeseen site restoration or salvage activities at a scale that cannot be accommodated within the FRSR accrual. No specific examples identified.

**REVIEW OF YUKON ENERGY CORPORATION
FUTURE REMOVAL AND SITE RESTORATION PROVISION
(NET SALVAGE)**

Submitted to:

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March 30, 2025

TABLE OF CONTENTS

1.0 INTRODUCTION.....3

1.1 Summary of Conclusions 3

2.0 YUKON ENERGY NET SALVAGE HISTORY 5

3.0 NET SALVAGE APPROACHES.....6

3.1 Background 6

3.2 The Traditional Approach 7

3.2.1 Implementation and Cost Impacts if Adopted 10

3.3 Capitalization Approaches 12

3.3.1 Implementation and Cost Impacts if Adopted 14

4.0 CONCLUSION.....16

ATTACHMENTS.....18

1.0 INTRODUCTION

Yukon Energy Corporation ("Yukon Energy") is a regulated public utility that maintains material capital assets in service. Similar to many utility peers, prior to 2005 Yukon Energy maintained a provision for Future Removal and Site Restoration ("FRSR") also commonly known as a Net Salvage provision ("Net Salvage") which encompassed both annual accruals and annual spending. The term Net Salvage is typically meant to encompass spending on asset removal, dismantling, disposal, and site restoration, net of any salvage receipts from sale of the spare parts or scrap – multiple terms are used in various contexts to describe this concept, but they are typically synonymous.

In a rate application before the Yukon Utilities Board ("YUB") in 2005, the regulator directed a change to the practice to be applied to managing the obligations and liabilities associated with asset end-of-life and Net Salvage costs and recoveries.

Prior to 2005, Yukon Energy used an approach to accruing for future costs and recoveries associated with asset end-of-life commonly known as the Traditional Approach to Net Salvage, where costs associated with future removal and dismantling costs net of salvage are accrued during an asset's life in a manner that parallels the straight-line depreciation. In YUB Decision 2005-12, the regulator indicated that the balance at year-end 2004 was \$5.757 million and annual accruals were approximately \$0.5 million. The YUB directed that Yukon Energy discontinue annual accruals to the FRSR, and that YEC should use the established balance for removal ("dismantling") costs in 2005 and subsequent years, until the balance in the liability reaches \$2 million, at which time Yukon Energy is to inform the YUB.

Now that the balance has reached this level, Yukon Energy is in a position to propose a new approach to managing the future cost of net salvage. This report reviews the two main approaches that Yukon Energy may elect to apply to managing Net Salvage, consistent with common regulatory practice in Canada.

1.1 SUMMARY OF CONCLUSIONS

With the termination of the drawdown phase established by YUB Decision 2005-12, two main alternatives arise as potential candidates for Yukon Energy to pursue for accruing and collecting Net Salvage or FRSR in future years.

The first candidate is what is known as the Traditional Approach, effectively the same approach used by Yukon Energy prior to 2005. This option would be challenging for Yukon Energy to implement, for two reasons. First is that Yukon Energy is somewhat limited in the data required to properly implement the approach. More important, after a period of draw-down, re-adopting the Traditional Approach will have material rate impacts which are exacerbated by the last 20 years of no collection. Were the Traditional

Yukon Energy Review of Net Salvage**March 30, 2025**

Approach to have been the preferred route for Yukon Energy and its regulator, the pause initiated in 2005 is counter to achieving long-term rate stability.

The second candidate is the approach used by a number of southern Canadian jurisdictions, based fundamentally around capitalizing the costs of net salvage and removal as part of any new replacement capital project, and only accruing in rates sufficient funding to address removal costs when no direct replacement project will be undertaken. This Capitalization Approach can be implemented today on a reasonable basis using available data, and without severe rate impacts. The approach also overlaps well with IFRS, and is a good match for Yukon Energy's long-lived and relatively permanent assets (e.g., hydro units and transmission lines that are likely to be maintained into the indefinite future or replaced in situ, even in a period of decarbonization initiatives).

On this basis, it is recommended that the Capitalization Approach be adopted.

The approach should be implemented by way of an annual appropriation to the FRSR regulatory asset account, based on 0.042% of gross plant. If a major upcoming terminal retirement is identified or an ARO has been recorded for a material asset, this amount should be increased to reflect this obligation as early as reasonable plans can be developed for the retirement, including timing and cost.

The account balances would only be drawn down for removal activities where there is no direct replacement asset.

Yukon Energy should also review and, if necessary, adapt its capitalization policies to ensure annual transactions accord with this approach.

Yukon Energy Review of Net Salvage**March 30, 2025****2.0 YUKON ENERGY NET SALVAGE HISTORY**

Prior to 2005, Yukon Energy used an approach to accruing for future costs and recoveries associated with asset end-of-life commonly known as the Traditional Approach to Net Salvage, where costs associated with future removal and dismantling costs net of salvage are accrued during an asset's life in a manner that parallels the straight-line depreciation.

Since 2005, Yukon Energy has continued to maintain the net salvage account (the FRSR) consistent with the direction in Board Order 2005-12 which terminated annual accruals. As there have been no annual accruals to the account, the balance has declined with time (as was expected). The progression of the account balance is shown in Table 1:

Table 1: FRSR Balances

Balances in FRSR by year
(\$000s)

	opening	spend/ recover	accrual (additions)	closing
2005	5,757	139		5,618
2006	5,618	535	-	5,083
2007	5,083	(158)	-	5,241
2008	5,241	73	-	5,168
2009	5,168	160	-	5,008
2010	5,008	243	-	4,764
2011	4,764	53	-	4,711
2012	4,711	-	-	4,711
2013	4,711	40	-	4,671
2014	4,671	-	-	4,671
2015	4,671	304	-	4,367
2016	4,367	8	-	4,359
2017	4,359	55	-	4,303
2018	4,303	340	-	3,963
2019	3,963	1,173	-	2,790
2020	2,790	53	-	2,738
2021	2,738	-	-	2,738
2022	2,738	49	-	2,689
2023	2,689	653	-	2,036
total		3,721		

Yukon Energy Review of Net Salvage**March 30, 2025**

As noted in Table 1, the balances reflect the ongoing spending and draw down of the account. It should also be noted that the account is not cash – it represents a balance sheet entry as a regulatory liability.

The spending on net salvage since 2005 is notably limited, averaging only \$196,000 per year. A review of projects comprising the spending since 2009 (\$3.1 million in total spend) indicates over half (more than \$1.7 million) is related to only three projects – the removal of Whitehorse Wind #1, Whitehorse Wind #2, and the decommissioning of Whitehorse diesel units from service (WD1, WD2, and WD3).

Even over the most recent 5 years, which are somewhat higher than previous years, Yukon Energy's average annual spending is \$0.376 million per year. This is a low level of spend on net salvage activities. For example, consider the following examples in Table 2 measured in relation to each utility's rate base:

Table 2: Average Annual Spending on Net Salvage Activities

\$M	period	Average annual net salvage spending	Rate Base	spend as a percentage of rate base
Yukon Energy	2019-2023	0.38	376	0.10%
ATCO Electric Yukon	2016-2024	0.61	140	0.44%
BC Hydro	2023-2030	59.00	23,237	0.25%
AltaLink Management	2019-2023	31.08	7,736	0.40%
Northwest Territories Power	2021-2024	2.17	364	0.60%

notes:

AEY per 2023 GRA

BC Hydro per F2023-F2025 GRA

AltaLink per AUC proceeding 26509

Yukon Energy rate base per 2023 GRA

NTPC per 2024-26 GRA

From the above data, it appears likely that Yukon Energy has approached use of the FRSR with restraint, likely accounting for costs as either capital or O&M, which could have been included in the FRSR based on utility industry practice.

3.0 NET SALVAGE APPROACHES**3.1 Background**

There are a number of different approaches to addressing the costs of Net Salvage for utilities in Canada. Common among these approaches is the recognition that the costs of Net Salvage comprising removal,

Yukon Energy Review of Net Salvage**March 30, 2025**

dismantling, site restoration etc. are appropriate utility costs for recovery from customers. The costs of removing an asset are a key part of the costs of the service provided by the asset. As such these costs are appropriately included in the utility Revenue Requirement for the purpose of setting rates.

Variations occur in establishing an approach to managing Net Salvage costs, comprised of the complementary consideration of *in which time period* the collection will occur and *at what varying level* which can be combined into a number of approaches. Each of the common approaches has different degrees of rate impact, cash flow implications, and data requirements.

There are also variations around whether the same approach will be applied to all removals, or only to a subset of removals, typically reflecting two types of removals:

- The concept of a **terminal retirement** is that the asset is being removed from service and no replacement or equivalent asset will be built in the same location to replace it.
- In contrast, an **interim retirement** relates to cases where the asset in question is being removed and replaced by a similar asset in the same vicinity. In utility operations, this is typically the far more common type of retirement.

The main projects cited for Yukon Energy's historical net salvage spending (wind turbine removal and Whitehorse diesel decommissioning) likely fit into the definition as a terminal retirement.

The three main variants for periods of collection are:

- 1) Collected concurrent with the asset's service life, which includes methods known as the **Traditional Method**, and the far less common **Constant Dollar Net Salvage (CDNS)** approach
- 2) Collected on a largely **Pay-As-You-Go** basis as the assets are retired (or in a short number of years close to the year of retirement).
- 3) Collected via **Capitalization** as part of the capital cost of any replacement asset installed at the time of the retirement of the first asset. This third approach is only an option for interim retirements.

In practice, utilities in Canada primarily make use of two approaches – first is the Traditional Approach, and second is a hybrid approach consisting of Capitalization for interim retirements, combined with an alternative approach (either Pay-As-You-Go or Traditional Approach) for terminal retirements.

3.2 The Traditional Approach

The Traditional Approach is the most common, and has been widely used for many years. This is the approach that Yukon Energy used before the YUB adopted the pause in 2005. Other examples include:

Yukon Energy Review of Net Salvage**March 30, 2025**

- ATCO Electric Alberta
- Northwest Territories Power Corporation
- AltaGas Utilities
- ATCO Gas
- FortisBC Inc.
- Naka Power NWT (previously Northland Utilities Limited (NWT)).

Of particular note to Yukon Energy are ATCO Electric Yukon and BC Hydro given proximity and common history.

ATCO Electric Yukon (AEY) (previously Yukon Electrical Company Limited, or YECL) used the traditional approach to net salvage in periods prior to 2009. In YUB decision 2009-2, the YUB directed that AEY should cease accruals related to Net Salvage, similar to the YEC approach directed in 2005, but continue to use the Net Salvage balance to pay for removal activity. This reduced AEY's revenue requirement for the accrual by approximately \$1 million per year for 2009¹. At the time AEY had a Net Salvage balance of \$4.7 million. AEY continued to use this approach until its 2023-2024 GRA, when the balance had declined to below \$0.5 million.² AEY proposed to reimplement the traditional approach, with an annual accrual of \$2.1 million per year (2024), which was approved by the YUB.³ The YUB, however, significantly reduced the net salvage estimates, leading to a net impact of \$0.940 million on 2024 revenue requirement⁴. The addition of \$0.940 million per year to revenue requirement was a material impact in that proceeding, given that AEY's own source revenue requirement (i.e., excluding fuel and purchased power) totals only \$30.995 million in 2024⁵.

BC Hydro received an order from its regulator, the British Columbia Utilities Commission (BCUC) to suspend accruals to its Net Salvage accrual account in 2005 (similar to the 2005 Yukon Energy direction). Prior to 2005, BC Hydro used the Traditional Method for Net Salvage accruals.⁶ The balance in 2005 was \$233 million, which was to be used to fund removal activities but with no new accruals.⁷ The previous accrual of \$17 million per year was terminated.⁸

¹ YUB Order 2009-2 Appendix A, page 21.

² YECL 2023-2024 GRA, section 7.2.

³ YUB Order 2024-01 Appendix A, section 5.3.5

⁴ AEY 2023-2024 GRA Compliance Filing, Attachment 1, Schedule 7.1

⁵ AEY 2023-2040 GRA Compliance Filing, Attachment 1, Schedule 1.1.

⁶ Based on the description in BCUC Order G-96-04.

⁷ BCUC Order G-96-04.

⁸ BCUC Order G-47-18 page 158.

Yukon Energy Review of Net Salvage**March 30, 2025**

By F2017, the Net Salvage balance was approaching zero⁹. As part of its F2017-F2019 RRA, BC Hydro proposed to implement the Pay-As-You-Go approach, by including the forecast annual dismantling costs into revenue requirement¹⁰. BC Hydro proposed a new regulatory deferral for dismantling costs, that would true-up actuals to forecasts to eliminate risk from BC Hydro for variances. The BCUC approved the new account for F2017-F2019 only, noting that the Pay-As-You-Go approach could lead to variances but that with experience, "BC Hydro should be able to provide its best estimate on site dismantling and restoration necessary for the facilities that it operates and manages. Any variance remaining from factors outside of management's control may not be significant enough to warrant the variance treatment for the forecast dismantling cost."¹¹ In short, as of F2017, the main components of the net salvage component of BC Hydro's costs were fully incorporated into a Pay-As-You-Go approach.

For F2020 to F2021, BC Hydro applied to extend the dismantling account due to the nature of the costs being non-controllable¹², but continued to apply the Pay-As-You-Go approach. No intervenor opposed this approach. The BCUC approved the extension of the account, but expressed concern with the level of dismantling costs (including a table showing over the previous 8 years, spending totaled \$267.3 million, or an average of \$33.4 million/year). The Commission noted:

However, the Panel also notes that dismantling costs have been increasing and is concerned with whether BC Hydro's approach to dismantling costs would result in intergenerational equity issues. In the Panel's view, the dismantling of property, plant and equipment, similar to negative salvage, should be paid for by the customers who benefited from the use of these assets. Therefore, the Panel directs BC Hydro to provide in its next RRA, an assessment of whether its current practice of expensing dismantling costs as they occur would result in intergenerational inequity and to provide options on how it could calculate and collect dismantling costs to better promote intergenerational equity. For these reasons, the Panel approves the use of the Dismantling Cost Regulatory Account, as requested by BC Hydro, for the Test Period only.

For F2022, BC Hydro sought approval to continue the dismantling deferral account, and indicated it was preparing a proposal for depreciation and net salvage¹³.

In its F2023-F2025 Revenue Requirement Application, BC Hydro sought to re-implement the Traditional Approach. BC Hydro estimated that a full implementation of the Traditional Approach, but without phase-

⁹ BCUC Order G-47-18, page 61.

¹⁰ BCUC Order G-47-18, page 61.

¹¹ BCUC Order G-47-18, page 62.

¹² BCUC Order G-246-20, page 122.

¹³ Order G-187-21, page 69.

Yukon Energy Review of Net Salvage**March 30, 2025**

in, would result in annual accruals of \$112 million in F2026.¹⁴ BC Hydro proposed to adopt the principle that the Traditional Approach should be used, but did not seek approval to begin accruals in the F2023-F2025 period. The BCUC approved the use of the Traditional Approach in principle, for implementation in F2026 subject to BC Hydro providing additional analysis on net salvage levels and phase-in impacts. This implementation and update of estimates has not yet occurred.

3.2.1 Implementation and Cost Impacts if Adopted

For Yukon Energy, re-adopting the traditional approach would reflect a common utility precedent in Canada, and matches the method adopted by peers who had a similar history with pausing then reinitiating their Net Salvage provision – specifically, AEY and BC Hydro.

However, there are two key issues with adopting the traditional approach at this time. The first is data limitations, and the second is revenue impacts.

On the first issue, Yukon Energy's experience with respect to data collection on net salvage (particularly for interim retirements) is likely a barrier to accurately implementing the Traditional Approach at this time. As noted earlier in this discussion, the Yukon Energy record appears to be heavily weighted towards terminal retirements with much less reflection of the costs of net salvage associated with interim retirements. It would normally be expected that the interim retirements experienced add up to many multiples of the costs recorded for terminal retirements, yet Yukon Energy's record with respect to interim retirements does not match this pattern (more than half of recorded net salvage costs are for terminal retirements). For example, AltaLink has filed estimates of terminal versus interim retirements that indicate interim retirements typically are 10 times the experience with terminal retirements¹⁵.

This low level of recorded spending for interim retirements is not consistent with the principles and development of estimates normally adopted for the Traditional Approach to Net Salvage. If the Traditional Approach is re-implemented, it will be important to ensure that capital asset policies for recording project costs appropriately track the removal portion of all capital jobs to permit appropriate allocation of spending to capital asset additions versus removal/net salvage costs.

A review of potential removal costs under a Traditional Approach requires three data components:

- 1) An estimate of the costs of removal as a percentage of the original cost to install an asset. These percentages are typically derived from a mixture of a utility's own data and a review of peers. Given Yukon Energy's limited own-source data, ratios have been developed focused on peers and

¹⁴ BC Hydro F2023-F2025 Revenue Requirement Application, Table 8-6.

¹⁵ AUC Exhibit 26509-X0023, AML-AUC-2021AUG20-011. Pdf page 26 of 315.

Yukon Energy Review of Net Salvage**March 30, 2025**

previous Yukon benchmarks. The comparison is provided in Attachment A1. Based on this review, estimated ratios as follows appear to be appropriate:

- a. Hydro assets – 10%
 - b. Diesel and LNG assets – 10%
 - c. Distribution – 20%
 - d. Transmission and subtransmission – 30%
 - e. General Plan, excluding Transportation – 5%
- 2) An estimate of the expected average remaining life of assets in service. Data for this is available from Yukon Energy's last depreciation study.
 - 3) A period for the "true-up" of any deficits or surpluses compared to the balance estimated to be required as of a given date. This is a significant portion of the cost impact of the Traditional Approach, as the present balance below \$2 million is far short of what would be in place had the Traditional Approach been retained in service throughout the intervening years. Even if only the previous \$0.5 million/year accrual had been continued (ignoring growth in the asset base), there would be approximately \$10 million additional in the FRSR today. For the purposes of this analysis, an approach based on recovering this true-up amount over the expected average remaining life has been assumed. This is the longest period that would normally be considered for a true-up (i.e., lowest rate impact).

Based on the above approach, there would be 2 components to the implementation of Net Salvage at this time:

- The ongoing normal annual accrual would total \$2.473 million/year. This is the estimated amount needed to keep up with the present plant in service. As spending is far below this level, the balance in the Net Salvage provision would grow quickly, reflecting building up to a balance that would be discharged with far-future expected major removal activities. While this is approximately 5 times the amounts that were being accrued in 2005 (at about \$0.5 million), this ratio is reasonably consistent with BC Hydro who saw their annual accrual grow from \$17 million to \$112 million, a ratio of 6.6 times. AEY also saw material growth of a factor of 2.2, but this was over a somewhat shorter period (15 years, as opposed to 20)
- The added need for a true-up provision is material, and is based on the relative procession of assets through their lives since the 2005 balance was set in decline. At this time, a fully-funded Net Salvage reserve balance is \$40.170 million (as compared to slightly over \$5 million in 2005,

Yukon Energy Review of Net Salvage**March 30, 2025**

and less than \$2 million today). Based on the amortization of the true-up over the expected average remaining life, this balance would lead to an additional annual expense of \$2.284 million.

Combined, the annual expense to implement the Traditional Approach at this time is estimated at \$4.742 million/year based on plant in service in 2024.

The calculation of the above figures is provided in Attachment A1, showing the derivation of the net salvage costs, and the salvage parameters compared to peers.

3.3 Capitalization Approaches

The most common alternative to the Traditional Approach is to adopt a procedure for interim retirements that uses the Capitalization approach, combined with a provision for accruals or expensing tied to terminal retirements.

This approach is not as common as the Traditional Approach, though it has been adopted in recent years for a number of utilities. The analytical basis ties to equitable treatment - at any given time, ratepayers will be shouldering all costs to finance and depreciate the original cost of the assets in service. For any given asset, the nominal cost of return and depreciation will decrease over time (as the asset is depreciated), and the real cost (especially in the case of load growth) will decline even faster. Yet every user of the system receives effectively the same service from the asset whether it is new or old (e.g., same kW produced or transmitted). Therefore, the most equitable time to recover salvage is in the latter years of the asset's life, when the same service is otherwise being delivered at a lower cost.

Outside of this mathematical relationship, there is also a solid basis in equitable treatment to conclude, for those assets that will be replaced in situ, that some of the benefit of the existing asset in fact accrues to the future customers served by second generation of the asset.

Taking into account the above factors, a number of regulators ultimately concluded to adjust the method of net salvage to include the costs of removal of any interim retirement into the capital costs of the replacement asset¹⁶.

This same broad type of methodology has been adopted in a number of cases in Canada, including the following:

- Altalink Utilities Inc.
- Manitoba Hydro

¹⁶ AUC Proceeding 25870

Yukon Energy Review of Net Salvage**March 30, 2025**

- Newfoundland Hydro
- EPCOR Utilities¹⁷

Other utilities, such as AltaGas¹⁸ and ATCO Gas¹⁹, have been directed to study the approach.

It is helpful to note the specific implementation details that differ to some degree among the main utility examples:

- Altalink is presently in a transition period, where charges for all removal costs (interim or terminal) are charged to the residual balance remaining from the period when Altalink used the traditional method (much like the Yukon Energy remaining Net Salvage balance). After this period is over, removal costs linked to replacement projects (i.e., interim retirements) will be charged to the capital cost of the replacement asset. Final terminal retirements will be expensed, which has not yet been operationalized, but is expected in practice to be included in revenue requirement through a deferral account treatment (effectively a Pay-As-You-Go funding model, with deferral and stabilization to fund ongoing occasional larger terminal removal activities).
- Manitoba Hydro includes removal costs for interim retirements as part of the capital cost of the replacement asset. As noted in Manitoba Hydro's 2020/21 Annual Report: "When the costs of removing an asset from service are incurred to facilitate the installation of a new asset, the costs to remove the asset from service are added to the costs of the new asset. When an asset is retired from service and not replaced with a similar asset, the costs of removing the asset from service are treated similarly to the net gain or loss on retirement of assets."²⁰ In effect, given the form of regulation for Manitoba Hydro, the gain or loss on retirement is expensed.
- Newfoundland Hydro uses the same approach as Manitoba Hydro for interim retirements. For final retirements, the Annual Report or NALCOR (the owner of Newfoundland Hydro's Regulated operations): "A significant number of Nalcor's assets include generation plants, transmission assets and distribution systems. These assets can continue to run indefinitely with ongoing maintenance activities. As it is expected that these assets will be used for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of the cost of decommissioning liability cannot be determined at this time. If it becomes possible to estimate the

¹⁷ Decision 22570-D01-2018 at para 91.

¹⁸ AUC Decision 24161-D03-2019

¹⁹ AUC Decision 24188-D02-2020.

²⁰ Manitoba Hydro 2020/21 Financial Statements, note 3(g).

Yukon Energy Review of Net Salvage**March 30, 2025**

fair value of the cost of removing assets that Nalcor is required to remove, a decommissioning liability for those assets will be recognized at that time.”²¹

In short, none of Altalink, Newfoundland Hydro, nor Manitoba Hydro ever accrues or expenses the costs of interim retirements, but instead considers these costs to be part of the cost of the replacement asset.

However, for terminal retirements, Newfoundland Hydro will accrue a balance, but not until later in an asset’s life when a reasonable estimate can be made of the fair value of the cost of removal. For Manitoba Hydro, these amounts are understood to be charged to accumulated depreciation and expensed (which in practice results in a regulatory treatment that later seeks recovery from ratepayers, as Manitoba Hydro does not operate with a strict annual revenue requirement model). For Altalink, the amounts are to be collected in a stabilized Pay-As-You-Go model.

3.3.1 Implementation and Cost Impacts if Adopted

An analysis of the Yukon Energy Net Salvage spending suggests that the majority of spending that has been tracked to the Net Salvage account represents terminal retirement activities.

On this basis, it can be assumed that a reasonable estimate for routine terminal retirements alone (not including interim retirements) can be developed from the long-term historical record, in relation to the asset base in place at the time. This data is shown in Table 3²²:

²¹ Note that the excerpt is from NALCOR’s 2020 Financial Statements MD&A page 44. This is in contrast to Concentric response to AMPC IR 1.38.5, which suggests NALCOR uses the “traditional” approach for terminal retirements. The above described approach to terminal retirements does not fit with the traditional approach as it only accrues balances late in an asset’s life.

²² Gross PPE from Yukon Energy Annual Reports up to 2014, and from Yukon Energy Regulatory Schedules from 2015 onwards, as filed with the YUB.

Yukon Energy Review of Net Salvage**March 30, 2025****Table 3: Spending in Relation to Gross PPE****FRSR Spending in Relation to Gross PPE**
(\$000s)

	spend/ recover	Gross PPE (including WIP)	Ratio
2005	139	222,116	0.063%
2006	535	226,567	0.236%
2007	(158)	237,646	-0.066%
2008	73	275,268	0.027%
2009	160	297,262	0.054%
2010	243	378,170	0.064%
2011	53	473,168	0.011%
2012	-	495,796	0.000%
2013	40	520,406	0.008%
2014	-	555,552	0.000%
2015	304	577,888	0.053%
2016	8	589,387	0.001%
2017	55	598,756	0.009%
2018	340	615,387	0.055%
2019	1,173	642,291	0.183%
2020	53	667,962	0.008%
2021	-	691,598	0.000%
2022	49	734,073	0.007%
2023	653	796,724	0.082%
mean			0.042%

Based on an estimated 2024 year-end Gross PPE of \$841.173 million, this would yield an estimated net salvage spending on terminal retirement activities of \$0.352 million.

The final consideration is the overlap with the IFRS Asset Retirement Obligation ("ARO"). It is understood that Yukon Energy has had little need to record AROs in recent years, so there has been no need to resolve any potential conflict between the activities meant to be reflected in the FRSR and AROs. Going forward, there is the potential of more significant AROs. To maintain a complementary operation of FRSR and AROs, it will be necessary to be clear on regulatory versus IFRS accounting. The FRSR is inherently a financial liability – it represents dollars collected for a purpose that have not yet been spent and are not income to the utility. The ARO is different in that it is an activity-based liability – a future activity that the utility is obligated to undertake. For regulatory purposes, the only account necessary to record is the FRSR, though the balance being targeted could be informed by an IFRS ARO. For example, if a large ARO is being

Yukon Energy Review of Net Salvage**March 30, 2025**

recorded, this is a sign the FRSR accrual should be increased over time to match the upcoming spend, if it is insufficient. For financial reporting purposes, further consideration of IFRS and the best way to reflect the interaction will be required. It would appear appropriate that the ARO and FRSR are structured to avoid double-counting of the same principles on the balance sheet. For example, the value of the FRSR reported on the balance may be best represented by being reported net of any ARO already recorded. However, further accounting advice may be required to consider alternatives, and whether additional direction is required from the regulator in respect of the FRSR regulatory asset.

Implementation of the Capitalization approach would therefore include three separate aspects:

- 1) **Interim Retirements:** A revision to Yukon Energy's capital asset policy that makes clear that any and all removal costs associated with removal of assets which are being effectively replaced in the same location are part of the capital cost of new assets in that location. If any change is necessary in practice, it should not be a major change, as it appears this is largely consistent with Yukon Energy practice (based on the low rate of charges to the FRSR provision). Also, this approach is routinely cited as being consistent with IFRS (for example, see Altalink AUC proceeding 23848).
- 2) **Routine Terminal Retirements:** Maintain the FRSR account as part of regulated ratemaking. Implementation of a new accrual in rates of 0.042% of gross PPE each year (approximately \$0.352 million/year) to sustain the account solely related to the estimated requirement for funding the costs of routine terminal retirements.
- 3) **Non-Routine Retirements:** Adoption of a practice that, if needed, any major non-routine terminal retirements are addressed at an early opportunity through accruals in rates. For example, if a major transmission or hydro asset is facing terminal retirement, costs for that activity should be estimated at an early opportunity and an accrual built into rates to build up the balances needed to undertake the removal activity. Note that this would be expected to be very rare (no such event is reflected in the 2005-2023 record).
- 4) **Addressing the overlap with ARO in financial reporting.**

With the above three provisions, it would be expected that the current FRSR balance of somewhat less than \$2 million would be sustained, and permit the annual provision to be maintained at the 0.042% level for a period of time, with the ability to absorb events of higher than average terminal retirement cost.

4.0 CONCLUSION

Based on the above considerations, Yukon Energy is advised to pursue a Capitalization approach to managing net salvage costs. The annual accrual should be set at 0.042% of Gross PPE, or approximately \$0.352 million per year, updated at each rate application. If a major upcoming terminal retirement is

Yukon Energy Review of Net Salvage**March 30, 2025**

identified or an ARO has been recorded for a material asset, this amount should be increased to reflect this obligation as early as reasonable plans can be developed for the retirement, including timing and cost.

ATTACHMENTS

Yukon Energy Review of Net Salvage

March 30, 2025

Attachment A1 – Calculation of Traditional Approach to Net Salvage

2018 Depreciation Study Parameters							Peer Utility Net Salvage Rates									
Asset Class ID	Asset Class ID Descriptions	2024 Forecast Gross Plant in Service	Amortization Rate based on Board Approved Life	Parameters (Order 2022-03)	Remaining Life	2024 Depreciation	BC Hydro 2021 Study (Decision G-91-23)	Fortis BC 2017 Study (Decision G-166-20)	NTPC 2020 Study (Phase-in)	Maritime Electric 2020 Depr Study	Estimated Average Net Salvage Rate for YEC	Annual Net Salvage Keep-up Provision (2024 Forecast)	Accum. Amor. Ratio to Gross Plant	Catch-up Amount	Annual Provision for Catch-up (2024 Forecast)	Total Net Salvage Provision (2024 Forecast)
Hydro Plant																
1615-200	Hydro-Strctrs & Imprvmts	55,493,770	72	1.39%	56.6	770,747		10%	8%				-30%	1,674,967	29,593	
1615-201	Hydro-Building & Imprvmts	10,441,993	40	2.50%	38.59	261,050		10%	8%				-30%	315,170	8,167	
1615-205 & 1615-206	Hydro-Rsvrs Dams & Wtrways	175,789,457	103	0.97%	73.55	1,706,694		25%	8%				-30%	5,305,850	72,139	
1615-504 & 1615-506	Hydro-Wtrwhls, Trbines & Gen's	40,243,046	85	1.18%	45.53	473,448		25%	8%				-30%	1,214,655	26,678	
1615-600	Hydro-Accessory Electric Equip	27,836,431	40	2.50%	28.8	695,911		20%	8%				-30%	840,186	29,173	
1615-601	Hydro-Accessory Digital Equip	872,322	20	5.00%	18.5	43,616		20%	8%				-30%	26,329	1,423	
1615-700	Hydro-Misc Power Plant Equip	12,191,310	30	3.33%	21.58	406,377		15%	5%				-30%	367,970	17,051	
1615-730	Hydro- Fences	108,787	30	3.33%	21.7	3,626		15%	8%				-30%	3,284	151	
	Hydro Plant Total	322,977,116				4,361,468	10%				10%	436,147	-30%	9,748,412	184,377	620,524
Diesel Plant																
1620-200	Diesel-Strctrs & Imprvmts	7,248,598	72	1.39%	42.77	100,675			13%	3%			-51%	372,369	8,706	
1620-201	Diesel-Building & Imprvmt	502,429	55	1.82%	47.65	9,135			13%	3%			-51%	25,810	542	
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	2,895,496	40	2.50%	26.04	72,387			25%	3%			-51%	148,745	5,712	
1620-500	Diesel-Gnrng Equip & Prime	12,891,063	40	2.50%	19.47	322,277			8%	3%			-51%	662,229	34,013	
1620-501	Diesel Assets Overhaul	3,136,061	11	9.09%	0	285,096			8%	3%			-51%	161,103	161,103	
1620-508	Diesel-Minto Gnrng Equip	257,792	12	8.33%	2.5	21,483			8%	3%			-51%	13,243	5,297	
1620-600	Diesel-Acc Electric Equip	9,527,355	45	2.22%	29.63	211,719			8%	3%			-51%	489,432	16,518	
1620-700	Diesel-Misc Power Plant Equip	1,984,007	30	3.33%	17.74	66,134			0%				-51%	101,921	5,745	
	Diesel Plant Total	38,442,802				1,088,906	10%				10%	108,891	-51%	1,974,853	237,637	346,527
Distribution System																
1625-300	Dist System - Poles & Fxtrs	15,550,611	40	2.50%	31.9	388,765		35%	5%	65%			-31%	963,342	30,199	
1625-304	Dist System - Brushing	62,748	50	2.00%	20.69	1,255		30%					-31%	3,887	188	
1625-305	Dist System - Survey Costs	929,248	50	2.00%	40.61	18,585							-31%	57,566	1,418	
1625-401	Dist System - O/H Cndctrs	400,625	50	2.00%	37.18	8,012		35%	5%	65%			-31%	24,818	668	
1625-410	Dist System - O/H Services	3,672,313	40	2.50%	22.4	91,808		35%	8%	65%			-31%	227,496	10,156	
1625-501	Underground Conduit	539,907	40	2.50%	37.65	13,498		30%		15%			-31%	33,447	888	
1625-510	Dist System - Undrgrnd Cnduit	60,805	40	2.50%	33.22	1,520		30%		15%			-31%	3,767	113	
1625-610	Dist System - Meters	438,246	16	6.25%	2.36	27,390		30%		5%			-31%	27,149	11,504	
1625-620	Dist System - Meter Equip	404,266	16	6.25%	2.82	25,267		30%		5%			-31%	25,044	8,881	
1625-710	Dist System - Sbstdn Equip	3,086,841	40	2.50%	25.29	77,171		25%		15%			-31%	191,226	7,561	
1625-720	Dist System - Sbstdn Buildings	90,834	55	1.82%	28.51	1,652		25%		15%			-31%	5,627	197	
1625-730	Dist System- Substation Fences	140,640	30	3.33%	26.51	4,688		25%		15%			-31%	8,712	329	
1625-815	Dist System - Street Lights	845,795	40	2.50%	27.69	21,145		15%	8%	25%			-31%	52,396	1,892	
1625-905	Dist System - Line Trxfomers	5,666,718	35	2.86%	14.33	161,906		30%	5%	22%			-31%	351,047	24,497	
1625-961	Dist System - Sentinel Lights	51,085	30	3.33%	16.01	1,703		15%	8%	25%			-31%	3,165	198	
	Distribution System Total	31,940,685				844,365	20%				20%	168,873	-31%	1,978,688	98,689	267,562
Main Transmission Facilities																
1635-300	Main Trx - Poles & Fxtrs	84,738,673	65	1.54%	39.74	1,303,672		35%	13%	90%			-27%	6,948,867	174,858	
1635-304	Main Trx - Brushing	17,035,511	60	1.67%	48.97	283,925		30%	13%				-27%	1,396,971	28,527	
1635-305	Main Trx - Survey Costs	4,368,839	60	1.67%	47.13	72,814		30%					-27%	358,260	7,602	
1635-402	Main Trx - O/H Cndctrs/Poles	20,539,508	60	1.67%	47.84	342,325		30%	13%	90%			-27%	1,684,311	35,207	
1635-404	Main Trx - O/H Cndctrs/Towers	282,607	60	1.67%	30.48	4,710		30%	13%	90%			-27%	23,175	760	
1635-710 & 1635-711	Main Trx - Sbstdn Equip	103,012,358	54	1.85%	35.95	1,907,636		25%	10%	15%			-27%	8,447,373	234,976	
1635-720	Main Trx - Sbstdn Buildings	9,056,011	55	1.82%	49.39	164,655		25%	10%	15%			-27%	742,625	15,036	
1635-730	Main Trx - Sbstdn Fences	279,051	30	3.33%	23.09	9,302		25%	10%	15%			-27%	22,883	991	
	Main Transmission Facilities Total	239,312,559			322.59	4,089,039	30%				30%	1,226,712	-27%	19,624,465	497,957	1,724,669

Yukon Energy Review of Net Salvage

March 30, 2025

2018 Depreciation Study Parameters							Peer Utility Net Salvage Rates									
Asset Class ID	Asset Class ID Descriptions	2024 Forecast Gross Plant in Service	Approved Life	Amortization Rate based on Board Approved Life Parameters (Order 2022- 03)	Remaining Life	2024 Depreciation	BC Hydro 2021 Study (Decision G-91-23)	Fortis BC 2017 Study (Decision G-166-20)	NTPC 2020 Study (Phase-in)	Maritime Electric 2020 Depr Study	Estimated Average Net Salvage Rate for YEC	Annual Net Salvage Keep- up Provision (2024 Forecast)	Accum. Amor. Ratio to Gross Plant	Catch-up Amount	Annual Provision for Catch-up (2024 Forecast)	Total Net Salvage Provision (2024 Forecast)
Sub Transmission Lines																
1640-300	Sub Trx - Poles & Fxtrs	4,645,012	65	1.54%	24.84	71,462		35%	13%	90%			-64%	885,606	35,652	
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,681,352	12	8.33%	2	223,446		30%	13%	90%			-64%	511,220	255,610	
1640-304	Sub Trx - Brushing	42,151	60	1.67%	58.52	703		30%					-64%	8,036	137	
1640-306	Sub Trx - Brushing Mnt Mn	438,290	12	8.33%	2	36,524		30%					-64%	83,563	41,782	
1640-307	Sub Trx - Survey Costs Mnt Mn	96,403	12	8.33%	2	8,034		30%					-64%	18,380	9,190	
1640-401	Sub Trx - O/H Cndctrs	1,862,351	60	1.67%	44	31,039		30%	13%	90%			-64%	355,071	8,070	
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	79,862	45	2.22%	14.12	1,775		30%					-64%	15,226	1,078	
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	932,947	12	8.33%	2	77,746		30%	13%	90%			-64%	177,873	88,937	
1640-710	Sub Trx - Sbstdn EEquip	8,200,567	54	1.85%	41.87	151,862		25%	10%	15%			-64%	1,563,499	37,342	
1640-711	Sub Trx - Sbstdn Equipmnt Mnt Mn	7,205,898	12	8.33%	2	600,491		25%	10%	15%			-64%	1,373,858	686,929	
Sub Transmission Lines Total		26,184,833				1,203,081	30%				30%	360,924	-64%	4,992,333	1,164,727	1,525,651
Buildings & Other Equipment																
1645-110	Bldg&Otr - Survey Costs Land	5,040	50	2.00%	17.18	101		5%		10%			-44%	111	6	
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	3,050,343	50	2.00%	44.39	61,007		5%		10%			-44%	66,903	1,507	
1645-201	Bldg&Otr - Building & Imprvmnt	13,329,109	55	1.82%	32.5	242,347		5%		10%			-44%	292,349	8,995	
1645-202	Bldg&Otr-Office Fmtr & Equip	2,307,989	20	5.00%	5.34	115,399		5%					-44%	50,621	9,480	
1645-210	Bldg&Otr - Comm Site Towers	22,508	40	2.50%	25.26	563		5%		10%			-44%	494	20	
1645-220	Bldg&Otr - Comm Site Fences	131,448	30	3.33%	20.65	4,382		5%		10%			-44%	2,883	140	
1645-320	Bldg&Otr - Computer Hardware	1,889,795	7	14.29%	2.99	269,971		5%		10%			-44%	41,449	13,863	
1645-330	Bldg&Otr - Computer Software	0	5	20.00%	2.55	0		5%		10%			-44%	0	0	
1645-505	Bldg&Otr - Tools & Instruments	3,748,061	20	5.00%	9.24	187,403		5%		10%			-44%	82,207	8,897	
1645-507	Bldg&Otr - Wind Mntng Equip	0	15	6.67%	1.5	0		5%		10%			-44%	0	0	
1645-605	Bldg&Otr - Comm Equip	6,718,210	20	5.00%	9.68	335,910		5%		10%			-44%	147,351	15,222	
1645-810	Bldg&Otr - Houses/Land	68,854	40	2.50%	29.85	1,721		5%		10%			-44%	1,510	51	
1645-820	Bldg&Otr - Houses/Buildings	2,510,576	40	2.50%	24.85	62,764		5%		10%			-44%	55,065	2,216	
Total Building		33,781,933				1,281,569	5%				5%	64,078	-44%	740,943	60,396	124,474
Transportation																
1650-411	Trxptn - Utility Vehicles	448,260	8	12.50%	3.97	56,033										
1650-412	Trxptn - Sedans & Stn Wagons	261,643	11	9.09%	4.74	23,786										
1650-420	Trxptn - Trucks & Pole Trailer	88,711	25	4.00%	18.81	3,548										
1650-430	Trxptn - Pole Trailer>10,000lbs	66,388	25	4.00%	16.97	2,656										
1650-440	Trxptn - Trucks 3/4 to 2 Ton	4,780,822	9	11.11%	5.24	531,202										
1650-470	Trxptn - Trucks > 3Tons	2,287,704	20	5.00%	13.79	114,385										
1650-490	Trxptn - Foremost	1,240,792	20	5.00%	11.58	62,040										
Total Transportation		9,174,321				793,650										
LNG Plant																
1665-200	Structures and Improvements	6,248,874	72	1.39%	68.85	86,790							-23%	140,601	2,042	
1665-403	Fuel Holders	13,337,568	60	1.67%	56.85	222,293							-23%	300,097	5,279	
1665-500 & 1665-504	LNG Generator	22,359,448	40	2.50%	37.64	558,986							-23%	503,091	13,366	
1665-600	Accessory Electric Equipment	3,693,853	45	2.22%	41.88	82,086							-23%	83,112	1,985	
1665-700	Miscellaneous Power Plant Equi	2,920,651	30	3.33%	26.95	97,355							-23%	65,715	2,438	
1665-730	LNG Fence	787,736	30	3.33%	26.88	26,258							-23%	17,724	659	
Total LNG		49,348,131				1,073,767	10%				10%	107,377	-23%	1,110,341	25,769	133,146
Total YEC		751,162,379				14,735,845						2,473,002		40,170,034	2,269,551	4,742,552

1 **REFERENCE:** June 30, 2025 Board Order 2025-12 Supplementary Information
2 submission, PDF page 7
3

4 **ISSUE:** Additional information for projects expected to be completed after 2025-
5 2027 test period
6

7 **PREAMBLE:** “At PDF 7 of YEC’s June 30, 2025, Board Order 2025-12
8 Supplementary Information submission, YEC provides a table that
9 shows the forecast final cost and expected year of project completion
10 for YEC projects that are expected to come into service after 2027.
11

12 The Board requests that YEC provide the information requested below
13 for each of following projects listed in the table on PDF 7 of YEC’s June
14 30th supplementary information submission:

- 15 • Wareham Dam Spillway Project - Full Replacement
- 16 • Whitehorse Power Expansion
- 17 • Mayo MH0 Plant Renewal or Replacement
- 18 • Carmacks Substation Relocate
- 19 • Office Building
- 20 • PLT Shop
- 21 • Renewable Resource Projects
- 22 • Protection and Control
- 23 • T9 Transformer Critical Spare
- 24 • EV Infrastructure Transition
- 25 • P126 Building Renovation
- 26 • Atlin Hydro SIS and EPA

27
28 **QUESTION:**
29

- 30 a) For each project noted above, please provide a complete project execution
31 schedule for the project as it existed at the time the expenditure forecasts included
32 in the present application were prepared. Please ensure that the project schedule
33 provided would allow the reader to determine, at minimum:
- 34 • any project activities completed by December 31, 2024.
 - 35 • the date by which expected procurement processes for anticipated project
36 construction labour and material contracts are anticipated to be (a) commenced
37 and (b) completed.

1 • the expected start and stop dates for significant sub-projects anticipated for the
2 project.

3

4 b) For each project noted above, please provide a detailed project budget reflecting
5 the internal YEC business case project cost forecast as it existed at the time YEC
6 management made the corporate decision to commence substantial expenditures
7 on the project. Please ensure that the project budget prepared for this response
8 provides a line-item cost breakdown at a reasonable level of line-item detail, and
9 which specifically includes line-items for allocated YEC internal costs, AFUDC
10 estimates, and contingency allowances.

11

12 **ANSWER:**

13

14 **(a) and (b)**

15

16 Overall, many of these projects had not yet commenced at the time the Application was
17 prepared so limited details were available other than what was included in the project
18 descriptions included in Appendix 5.4A. Therefore, for the following projects, there were
19 no project activities completed by December 31, 2024, a project execution schedule did
20 not exist at the time the expenditure forecasts included in the application were prepared,
21 and Yukon Energy management had not made the corporate decision to commence
22 substantial expenditures on the project so a detailed project budget reflecting the internal
23 YEC business case project cost forecast did not exist.

24

- 25 • Wareham Dam Spillway Project – Full Replacement
- 26 • Mayo MH0 Plant Renewal or Replacement
- 27 • Carmacks Substation Relocate
- 28 • Office Building
- 29 • PLT Shop
- 30 • Renewable Resource Projects
- 31 • Protection and Control – WD0
- 32 • EV Infrastructure Transition
- 33 • P126 Building Renovation

34

35 Information on project execution schedules for the remaining projects as it existed at the
36 time the expenditure forecasts included in the application were prepared, and a detailed
37 project budget reflecting the internal YEC business case project cost forecast as it existed

1 at the time YEC management made the corporate decision to commence substantial
2 expenditures on the project, is below.

3
4 **i. Whitehorse Power Expansion**

5
6 The project description is provided in the Application at section 5.4A-1 on PDF
7 page 440. Information as it existed at the time the Application was prepared is
8 provided below in response to the above questions. Updates on this project, which
9 is now referenced as the Whitehorse Power Centres Project, are provided in
10 response to YUB-YEC-1-8 (a-b) and its Attachment 1.

11
12 Yukon Energy had forecasted \$200,200 in project costs by the end of 2024. In
13 2024, significant work was conducted to understand the upgrades needed to
14 support load growth in Whitehorse and the technical requirements to increase
15 reliability and resiliency of the electricity infrastructure. Work undertaken to date
16 includes a fuel assessment, plant options analysis, transmission and distribution
17 analysis, and other system impact evaluations. Project activities also included a
18 preliminary engineering study to assess multiple locations and the most cost-
19 effective solution for the Yukoners.

20
21 Yukon Energy has been having discussions with First Nation governments, the
22 City of Whitehorse and YG to assess options to secure land that could be used for
23 a new generating site. Once land options have been identified, Yukon Energy
24 expects to conduct the following actions:

- 25
- 26 • In 2025, conduct air and noise modelling and detailed design for up to 15
27 MW; begin engagement and YESAB assessment for this site.
 - 28
 - 29 • In 2026, complete the assessment and permitting process, construct the
30 south power centre site, and add any new rental generation needed to meet
31 winter 2027/28 peak demands for electricity; and
 - 32
 - 33 • In 2027-2030, start construction of the north power centre and until
34 construction is complete, add rented or owned generation to the south
35 power centre site to meet winter peak demands for electricity.

1 With the smaller site in south Whitehorse in-service, work to build a larger
2 generation site and the necessary transmission system improvements needed to
3 support a large urban centre could begin. The engineering Transmission and
4 Distribution Study found that splitting required generation into two sites near the
5 load growth is ideal. Developing two sites supports reliability and reduces N-1
6 contingency risks associated with one large site in the north of Whitehorse
7 transmitting electricity to the south. The generation and associated system
8 upgrades can be built in two phases to spread out investment and resources. As
9 well, the McIntyre Substation requires an upgrade within this timeline, and the
10 upgrades are dependent on the location of the generation in the north.

11
12 This scope of work will ensure Yukon Energy can meet winter capacity needs on
13 the YIS through 2040 and increase the reliability of the transmission system around
14 Whitehorse. The general sequence and phasing of buildout as expected when the
15 GRA was filed is provided below:

- 16
17 • In 2025, work with stakeholders and rightsholders to identify potential sites
18 for north and south power centres and the substation, and complete
19 desktop assessments of the sites to identify any “showstoppers” that would
20 prevent a power centre or substation being built on site;
21
- 22 • In 2025-2026, narrow down a list of sites to one in the south, two in the
23 north (one primary and a second contingency site), and a substation
24 location, conduct baseline assessments in the field and permitting of all
25 proposed generating sites in the south and north of Whitehorse and the
26 substation site. YESAB has suggested that all four sites be combined into
27 one Executive Committee Screening to make the assessment process
28 more efficient. Permitting would occur by end of 2026;
29
- 30 • Design and development of facilities was then expected to proceed in
31 phases between 2026-27 and 2030 to 2035, as described in Appendix 5.4
32 of the application, page 5.4A4-2, resulting in 60 to 105 MW of thermal
33 power capacity.
34

35 Assessment and regulatory work was expected to be intensive in 2025 and 2026
36 and expected to be complete by Q4 2026. Once potential sites have been identified
37 Yukon Energy would initiate the YESAA process by submitting a Project

Description in Q2 2025. Engagement would be more intensive once the Project Description was submitted. The assessment of the project would be conducted under the YESAA Executive Committee screening process. Next, Yukon Energy would develop the YESAA Project Proposal. The Project would consider all sites necessary for the Project, including the two primary generating sites, the third contingency site, the new substation site and transmission line corridors.

The purpose of the assessment is to secure permits for the generating facilities for decades into the future. Both YESAB and the regulator (YG-ENV for the air emissions permit) support our approach to assess and permit more generation capacity than we intend to install. This allows Yukon Energy to expand the facilities and/or build the third contingency site without conducting another assessment. Yukon Energy has also been successful in assessing the facilities for longer periods, which allows for renewal of a permit under the same assessment. This is a similar assessment and permitting approach to the Callison Substation project where it was assessed and permitted for 15.5 MW but installed 6.5 MW for a temporal scope of 20 years (i.e., 20-year assessment allows for 2 x 10-year Air Emissions Permits).

The initial project budget (in \$000's), to be refined when new information is available, is below.

Activity	2025	2026	2027	2028	2029	Total
Internal Labour	160	200	300	300	300	1,260
Engagement and Partnerships	250	250	100	100	100	800
Siting	200	100	-	-	-	300
Assessment and Regulatory	550	700	100	-	-	1,350
Design	200	1,250	10,000	-	-	11,450
Construction	-	10,000	39,500	49,600	9,600	108,700
Total by Year	1,360	12,500	50,000	50,000	10,000	123,860
Contingency	136	-	-	-	-	136
Budget Total ^a	1,500	12,500	50,000	50,000	10,000	124,000

The initial project budget did not separately disclose AFUDC.

1 **ii. Protection and Control – S170**

2
3 The project description is provided in the application at section 5.4A-13 on PDF
4 page 463.

5
6 Yukon Energy had forecast \$18,600 in project costs by the end of 2024. Yukon
7 Energy engaged SNC Lavalin in 2020 to complete a system wide assessment of
8 its protection, control and SCADA assets as part of the Physical Asset
9 Management Managed System (PAMMS) implementation. The assessment
10 included a site visit, data collection of assets, and evaluation of equipment asset
11 health indices (AHI) based on age, obsolescence, physical condition and type.
12 SNC has developed a 20-year asset management plan to replace protect and
13 control assets in the Yukon Energy electrical grid.

14
15 Assessments need to be conducted prior to moving forward with completion of this
16 project. Therefore, due to uncertainty, this project has not been included in rate
17 base and remains in work-in-progress.

18
19 **iii. T9 Transformer Critical Spare**

20
21 The project description is provided in the application at section 5.4A-12 on PDF
22 page 462.

23
24 Yukon Energy had forecast \$58,200 in project costs by the end of 2024. Costs to
25 date include transformer assessments and testing including visual checks, surge
26 arrester testing, insulation resistance, ratio test, winding resistance, dielectric
27 frequency response, oil DGA analysis, thermal imaging for hot spots, bushing CT
28 (current transformer) test, complete electrical and non-electrical tests.

29
30 Costs of \$325,000 in 2026 are forecast to be for procurement requirements. Long
31 lead times for large power transformers are in the range of 4-5 years. The final
32 cost will be dependent on future market conditions.

33
34 **iv. Atlin Hydro Energy Purchase Agreement**

35
36 The project description is provided in the application at section 5.4B-1 on PDF
37 page 466.

1 Yukon Energy had forecast \$1.682 million in project costs by the end of 2024, with
2 corresponding contributions of \$0.356 million, for net project costs of \$1.326
3 million.

4

5 The Atlin Hydro Expansion Project was identified in Yukon Energy's 10-Year
6 Renewable Electricity Resource Plan. This led to the negotiation of an Energy
7 Purchase Agreement (EPA) between Yukon Energy and Tlingit Homeland Energy
8 Limited Partnership (THELP). Project costs to date include the legal and contractor
9 costs to negotiate the Atlin EPA and accompanying agreements.

10

11 Yukon Energy has not performed significant work on this project since the 2023/24
12 GRA. The most significant update is that the EPA conditions precedent between
13 Yukon Energy and THELP have been extended to January 31, 2026, confirming
14 that the EPA is still alive. The 2025 forecast costs are dependent on finalization or
15 extension of the conditions precedent.

1 **REFERENCE:** YEC 2025-2027 Application, Table 5.8, PDF page 228-233

2
3 **ISSUE:** Additional information for projects expected to be completed after 2025-
4 2027 test period

5
6 **PREAMBLE:** The Board wishes to obtain additional information about projects
7 included on those projects listed in Table 5.8 that were not previously
8 considered by the Board in the proceeding that examined YEC's 2023-
9 2024 or any prior YEC GRA proceeding.

10
11 **QUESTION:**

12
13 a) Please provide a list all projects noted in Table 5.8 that:

- 14
15
 - are included in the "Major projects > \$2 million" categories;
 - are part of Generation, Transmission, Distribution, General Plant, and
 - 16 Overhaul categories;
 - 17 • are not anticipated to have capital additions after 2027; and
 - 18 • have not been assessed in a prior GRA proceeding
 - 19

20
21 b) For each project provided in your response to part (a) above, please provide the
22 relevant 2025-2027 GRA business case appendix number and corresponding
23 business case page range that pertains to the project.

24
25 c) For each project identified in your part (a) response, please provide a complete
26 project execution schedule for the project as it existed at the time the expenditure
27 forecasts included in the present application were prepared. Please ensure that
28 the project schedule provided would allow the reader to determine, at minimum:

- 29
30
 - any project activities completed by December 31, 2024.
 - 31 • the date by which expected procurement processes for anticipated project
 - 32 construction labour and material contracts are anticipated to be (a)
 - 33 commenced and (b) completed.
 - 34 • expected start and stop dates for significant sub-projects anticipated for the
 - 35 project.

d) For each identified in your part (a) response, please provide a detailed project budget reflecting the internal YEC business case project cost forecast as it existed at the time YEC management made the corporate decision to commence substantial expenditures on the project. Please ensure that the project budget prepared for this response provides a line-item cost breakdown at a reasonable level of line-item detail, and which specifically includes line-items for allocated YEC internal costs, AFUDC estimates, and contingency allowances.

ANSWER:

(a) to (b)

The applicable projects and location in the application is below.

Category of capital project	Business Case Appendix Number	PDF Page Ranges
Capital Projects – Major projects > \$2 million		
Generation		
Wareham Dam Spillway Project - Tunnel	5.1A-4	267-271
Battery Energy Storage System	5.1A-2	243-254
MH0 rockslide Stabilization and Remediation	5.1A-3	255-266
MH0 Surge Chamber Replacement	5.1A-5	272-275
WH3 Headgate Replacement	5.1A-11	295-298
Dam Safety Review Mitigations	5.1A-10	293-294
Transmission		
Spare Power Transformer Program	5.1A-9	288-292
Transmission line hazard tree reduction and ROW widening program	5.1A-8	283-287

(c) to (d)

Information on project execution schedules for the above projects in (a-b) as it existed at the time the expenditure forecasts included in the application were prepared, and a detailed project budget reflecting the internal Yukon Energy business case project cost forecast as it existed at the time Yukon Energy management made the corporate decision to commence substantial expenditures on the project, are provided below.

i. Wareham Dam Spillway Project - Tunnel

1 A project execution schedule for the project as it existed at the time the expenditure
2 forecast included in the present application was prepared is below.
3

Milestone / Deliverable	Original	Revised	Actual	Status
Phase 1 Preliminary Engineering – Current Charter				
Board of Director Project Approval	Q2 2024		Q2 2024	COMPLETED
Option Development and Selection	Q2 2024		Q2 2024	COMPLETED
Submission of Emergency Amendment Application for the Water Use Licence (WUL) and Fisheries Act Authorization (FAA)	Q2 2024	Q1 2025		IN PROGRESS
Decision on Procurement Approach for Contractor	Q2 2024	Q4 2024		COMPLETED
Contract Award (Design Engineer and Contractor)	Q2-Q4 2024	Q1-Q3 2025		IN PROGRESS
Secure Emergency Amendments to WUL and FAA	Q2 2024	Q2 2025		IN PROGRESS
Site Investigation Complete	Q2 2024	Q3 2024		COMPLETED
Early Contractor Engagement at 30% project design	Q2/Q3 2024	Q3/Q4 2024		CANCEL
End of Design of Cofferdam (TBD)	Q3 2024	Q2-Q3 2025		IN PROGRESS
Submit Construction Plan for Cofferdam for Regulatory Review and Approval	Q3 2024	Q3 2025		NOT STARTED
Secure Approval to Construct Cofferdam from YWB and DFO	Q3 2024	Q3 2025		NOT STARTED
Start Construction of cofferdam (TBD)	Q3/Q4 2024	Q3/Q4 2025		NOT STARTED
Phase 2 Project Execution				
Class 3 Estimate	Q3 2024	Q4 2024		COMPLETED
Final Design Complete (Auxiliary spillway only)	Q4 2024	Q2 2025		IN PROGRESS
Submit Construction Plan for Permanent Spillway for Regulatory Review and Approval	Q1 2025	Q4 2025		NOT STARTED
Secure Approval to Construct Permanent Spillway from YWB and DFO	Q2 2025	Q4 2025		NOT STARTED

Milestone / Deliverable	Original	Revised	Actual	Status
Start of Construction of Spillway	Q2 2025	2026		NOT STARTED
Spillway Commissioned	Q4 2026	2027		NOT STARTED
Design of Decommissioning of existing Spillway (TBD)	Q1 2025	Q1/Q2 2025		NOT STARTED
Submit Decommissioning Plan for Existing Spillway for Regulatory Review and Approval	Q1 2025	Q4 2025		NOT STARTED
Secure Approval to Decommissioning Existing Spillway from YWB and DFO	Q2 2025	Q4 2025		NOT STARTED
Decommissioning of existing Spillway (TBD)	Q2 2027	2026/27		NOT STARTED

The detailed project budget reflecting the internal YEC business case project cost forecast as it existed at the time Yukon Energy management made the corporate decision to commence substantial expenditures on the project is below.

	2024 WIP	2025	2026	2027	Total
Contractor	\$3,383,046	\$750,000	\$23,515,000	\$23,000,000	\$50,648,046
Consultant		\$3,345,000	\$534,000	\$489,000	\$4,368,000
Internal	\$302,516	\$150,000	\$150,000	\$150,000	\$752,516
Materials (Gates)			\$5,000,000		\$5,000,000
Subtotal	\$3,685,562	\$4,245,000	\$29,199,000	\$23,639,000	\$60,768,562
AFDUC (3% Annually)	\$26,404	\$127,350	\$875,970	\$709,170	\$1,738,894
Risk Based Contingency (20%)		\$849,000	\$5,839,800	\$4,727,800	\$11,416,600
Total	\$3,711,967	\$5,221,350	\$35,914,770	\$29,075,970	\$73,924,057

ii. Battery Energy Storage System

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is below.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-70

Milestone / Deliverable	Original	Revised	Actual	Status
Limited Notice to Proceed (LNTP) Agreement with Vendor*	Feb 11, 2022	-	Q1 2022	Complete
Contract Negotiation with Preferred Battery Vendor	Feb 11, 2022	-	Q3 2022	Complete
Issue PO for Battery Vendor and EPC Contractor	Feb 14, 2022	-	Q3 2022	Complete
Access road development and site grading	Apr 29, 2022	-	Q3 2022	Complete
Fall Civil Work (helical pile foundation)	Sep 30, 2022	-	Q3 2023	Complete
BESS and BoP IFC Drawings Issued	Jul 22, 2022	Q4, 2024*	-	In Progress
Delivery of BESS and long lead items	Nov 7, 2022	Q2, 2025	-	In Progress
34.5 kV line construction complete	Jan 13, 2023	Q1, 2025*	-	In Progress
Construction completed	Mar 3, 2023	Q3, 2025	-	In Progress
Integration, Site Acceptance Testing, and commissioning	Mar 15, 2023	Q4, 2025	-	In Progress
Training	Mar 28, 2023	Q4, 2025	-	Not Started
BESS In-service	Mar 29, 2023	Q4, 2025	-	Not Started

* Target date has passed

The detailed project budget reflecting the internal YEC business case project cost forecast as it existed at the time Yukon Energy management made the corporate decision to commence substantial expenditures on the project is below.

Category	Costs to End of December 31, 2024	Forecast at Completion	Board Approved Budget	Variance
Owner's Engineer	893	1050	438	-612
Feasibility & Engineering	822	834	754	-80
Project Management	952	1020	327	-693
Permitting & Assessment	193	207	223	16
Public Engagement & Communications	100	151	124	-27
First Nations Engagement	43	353	156	-197
YEC Internal Labor	648	802	500	-302
EPC Contractor	15,932	26,932	27,128	196
34.5 kV Line Construction	146	146	150	4
AFUDC	971	1,276	526	-750
Subtotal	20,700	32,771	30,326	-2,445
Contingency	0	2,186	4,631	2,445
Project Total	20,700	34,957	34,957	0

iii. MH0 Rockslide Stabilization and Remediation

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

- Award of construction for the project was expected in April 2025. The award has subsequently been completed.
- Construction is to be completed in 2025 and 2026 construction seasons.
- Project in-service is expected in fall 2026, following completion of construction.

The detailed project budget reflecting the internal YEC business case project cost forecast as it existed at the time Yukon Energy management made the corporate decision to commence substantial expenditures on the project is below.

Items	2023-2024 (\$000's)	2025 (\$000's)	2026 (\$000's)	Total (\$000's)
Contractor	1,332	35,000	25,000	61,332
Consultant	1,580	550	575	2,705
YEC Internal Cost	189	175	200	563
Materials	9			9
Subtotal	3,110	35,725	25,775	64,610
AFUDC	78	536	1,458	2,072
Contingency		5,981	5,981	11,963
Total	3,188	42,242	33,215	78,645

iv. MH0 Surge Chamber Replacement

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

Milestone / Deliverable	Date	Status
2022 BOD Stage gate approval for \$350,000 (Stagegate 2)	Q1 2022	COMPLETE
Contract Award for Engineering Support	Q1 2022	COMPLETE
Transient Analysis of MH0 Facility	Q2 2022	COMPLETE

Milestone / Deliverable	Date	Status
Completion of Engineering Specifications for Surge Tank Replacement.	Q2 2022	COMPLETE
Development of RFP for Site Works	Q3 2022	COMPLETE
Scan of Surge Tank	Q2 2023	COMPLETE
Finalize Bulkhead Specifications	Q2 2023	COMPLETE
Purchase and Delivery of Bulkhead	Q3 2025	IN PROGRESS

Construction is to be completed in the 2025 and 2026 construction seasons. Project in-service is expected in fall 2026, following completion of construction.

The detailed project budget reflecting the internal YEC business case project cost forecast as it existed at the time Yukon Energy management made the corporate decision to commence substantial expenditures on the project is below.

Items	2022-2024 (\$000's)	2025 (\$000's)	2026 (\$000's)	Total (\$000's)
Contractor			20,250	20,250
Consultant	448	130	275	823
YEC Internal Cost	110	20	105	236
Materials	623	1,200	300	2,123
Subtotal	1,182	1,350	20,930	23,432
AFUDC	29	24	358	411
Contingency		1,000	2,987	3,988
Total	1,211	2,624	23,995	27,831

v. WH3 Headgate Replacement

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

This project was scheduled to start in 2024 with a plan for construction in spring 2025. Based on the water levels in the reservoir upstream of P125 and winter conditions in Whitehorse the construction window has been identified as September to November 2025. Key milestones are as follows:

- RFP Closing: February 2025. This has been completed.

- Project Award: March 2025. This has been completed.
- Design: March to April 2025. This has been completed.
- Manufacturing and Delivery: April to August 2025. This has been completed.
- Site Construction and Commissioning: September to November 2025.

The following table shows major cost components for the project.

Item	Cost
Yukon Energy Internal Cost	\$160,000
Contractor	\$2,200,000
AFUDC	\$25,000
Contingency	\$150,500
Total	\$2,535,500

vi. Dam Safety Review Mitigations

The projects are all located within the WRGS facilities. A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

- The 2025 spending is to finish the last few mitigation projects from the 2020 DSR that require completion.
- Mitigation projects for 2026 to 2029 shall be defined as per the Dam Safety Review to be completed in 2025.

Higher spending is expected as the newly identified high priority items will be addressed first.

The following table shows major cost components for the project.

Item	2025	2026	2027
Yukon Energy Internal Cost	\$75,000	\$125,000	\$125,000
Consultant & Contractor	\$225,000	\$1,075,000	\$975,000
Total	\$300,000	\$1,200,000	\$1,100,000

AFUDC is expected to be minimal as each project within the program is removed from WIP as soon as each project is completed.

vii. Spare Power Transformer Program

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

- In 2025, the work plan is to develop a list of spare transformers to procure. Once Yukon Energy has a list of spare transformers required, options can be considered for partnership with another utility (e.g. ATCO) to share capital spares, or how best to procure units. Based on current information, Yukon Energy expects that it will join the ATCO procurement process to take advantage of economies of scale.
- 2026 is for selection and award of contract for purchase of units.
- 2027 anticipates delivery of the first unit on an optimistic lead time of less than 2 years.

The following table shows major cost components for the project.

Item	2025	2026	2027	Total
Yukon Energy Internal Cost	\$25,000	\$25,000	\$0	\$50,000
Consultant	50,000	0	0	50,000
Contractor	0	250,000	2,325,000	2,575,000
Total	\$75,000	\$275,000	\$2,325,000	\$2,675,000

AFUDC is expected to be minimal as the majority of costs do not occur until transformer delivery.

viii. Transmission Line Hazard Tree Reduction and ROW Widening Program

A project execution schedule for the project as it existed at the time the expenditure forecast included in the present application was prepared is as follows:

- Based on the vegetation inventory obtained, ATCO recommends that in 2025, the only capital maintenance program planned for off-ROW

vegetation is to complete the mechanical widening on L171 and to start this program on L170.

- Based on the vegetation inventory obtained, ATCO recommends that in 2026, the only capital maintenance program planned is a portion of L170 to be mechanically widened.
- Based on the vegetation inventory obtained, ATCO recommends that in 2027, the only capital maintenance program planned is on another portion of L170 to be mechanically widened.

The following table outlines the expected capital costs in 2025.

Project – Line #	Hazard Tree - #of Trees	Hazard Tree (\$)	Danger Tree - # of Trees	Danger Tree (\$)	Mechanical Widen (m ²)	Mechanical Widen (\$)
L171	0	0	0	0	240,372	841,302
L170	0	0	0	0	31,208	108,598
Total	0	0	0	0	271,400	949,900

The following table outlines the expected capital costs in 2026.

Project – Line #	Hazard Tree - #of Trees	Hazard Tree (\$)	Danger Tree - # of Trees	Danger Tree (\$)	Mechanical Widen (m ²)	Mechanical Widen (\$)
L170	0	0	0	0	271,400	949,900
Total	0	0	0	0	271,400	949,900

The following table outlines the expected capital costs in 2027.

Project – Line #	Hazard Tree - #of Trees	Hazard Tree (\$)	Danger Tree - # of Trees	Danger Tree (\$)	Mechanical Widen (m ²)	Mechanical Widen (\$)
L170	0	0	0	0	271,400	949,900
Total	0	0	0	0	271,400	949,900

REFERENCE: YEC 2025-2027 Application, PDF pages 242, 246, 249-251, 260, 299, 306, 394, 419, and 425

ISSUE: Treatment of contingency allowances

PREAMBLE: Some, but not all of the business cases filed with the application include either project budget breakdowns or other project cost breakdowns that reference include line items for contingency allowances. Since not all capital project write-ups include detailed line-item cost breakdowns, it is not clear whether the forecasts for all capital projects discussed in the application have made allowances for project contingencies, or if the treatment of contingency allowances is applied consistently across all projects.

The Board has identified the following projects that have indicated that the project cost forecast has included a contingency allowance:

- Thermal Replacement (16.5 MW) project (Appendix 5.1A-1) (PDF 242)
- Battery Energy Storage System project (Appendix 5.1A-2) (PDF 246, 249, 250, 251)
- MH0 Rockslide and Stabilization and Remediation (Appendix 5.1A-3) (PDF 260)
- Wareham Dam Spillway – Tunnel (Appendix 5.1A-4) (PDF 271)
- MH0 Surge Chamber Replacement (Appendix 5.1A-5) (PDF 274)
- Transmission Line Refurbishment L178 (Appendix 5.1A-6) (PDF 279)
- Dawson Voltage Conversion Project (Appendix 5.1A-7) (PDF 282)
- WH3 Headgate Replacement project (Appendix 5.1A-11) (PDF 260)
- WH3 10-Year Overhaul project (Appendix 5.1A-12) (PDF 299)
- Lewes River Boat Lock project (Appendix 5.1B-1.1) (PDF 306)
- Integrated Resource Plan (Appendix 5.2A-5) (PDF 419)
- Demand Side Management program (Appendix 5.2B-2) (PDF 425)
- AGS 25-Year Water Use Licence Renewal (Appendix 5.2A-2) (PDF 394)

1 **QUESTION:**

2
3 a) Please provide a complete description of YEC's practice for determining
4 contingency allowance forecast in its capital project budgets.

5
6 b) Please confirm that all capital projects either completed during the 2023-2024
7 period or forecasted for in the application for the 2025-2027 test period or beyond
8 have utilized the contingency allowance forecasting approach described in your
9 response to part (a) above. If this cannot be confirmed, please provide a list of all
10 projects for which a contingency allowance was determined through a
11 methodology other than as described in your part (a) response. For any of the
12 projects noted in the preamble that YEC may identify as having used a different
13 approach to setting the contingency allowance than as described in your response
14 to part (a), please provide an explanation of how the contingency allowance
15 forecast was derived.

16
17 c) Please confirm that YEC does not draw down contingency allowance balances on
18 specific projects until the forecast budget of all other forecast elements have been
19 exhausted. If this cannot be confirmed, please explain YEC's practices for initiating
20 contingency allowance drawdowns and for determining the amount of the
21 drawdown that is applied at any given time.

22
23 d) Please explain YEC's practices for deciding that an increase in a project's
24 contingency allowance from the amount set in the initial project forecast is needed
25 and, if it is needed, for determining the amount of the contingency allowance
26 increase that should be applied.

27
28 **ANSWER:**

29
30 **(a)**

31
32 For projects above \$2 million (the level at which projects require Yukon Energy Board
33 approval), Yukon Energy establishes the contingency allowance through a structured risk
34 identification process. As part of the project risk assessment, potential risks with cost
35 impacts are identified, assigned an estimated cost, and evaluated against the likelihood
36 of occurrence. The aggregate of these quantified risks forms the contingency allowance
37 included in the project budget.

1 For projects under \$2 million, the contingency amount is established at the discretion of
2 the project manager, drawing on input from Yukon Energy subject matter experts and
3 informed by data from similar historical projects.

4
5 **(b)**

6
7 Confirmed.

8
9 **(c)**

10
11 Not confirmed. Project contingency allowances are accessed when the pre-identified risk
12 from the risk register materializes. The drawdown in the contingency allowance is based
13 on the actual cost of the risk event, not the amount used to estimate the original
14 contingency budget.

15
16 **(d)**

17
18 An increase to the project contingency budget is extremely rare and would be handled on
19 a case-by-case basis. This would only occur in the case of a significant change to the
20 scope (and update of the complete project budget) or major change to a project risk (for
21 example, the introduction of tariffs).

1 **REFERENCE:** YEC 2025-2027 Application, Table 5.1A-3, PDF page 242, Table
2 5.1A-7, PDF page 249, Table 5.1A-38, PDF page 299, and Table
3 5.1B-2, PDF page 306

4
5 **ISSUE:** Owners engineer expenditures
6

7 **PREAMBLE:** Business cases for the following projects have include project cost
8 breakdowns that include line items for expenditures on an “owners
9 engineer:”

- 10 • Thermal Replacement (16.5 MW) project (Appendix 5.1A-1)
- 11 • Battery Energy Storage System project (Appendix 5.1A-2)
- 12 • WH3 10-Year Overhaul project (Appendix 5.1A-12)
- 13 • Lewes River Boat Lock project (Appendix 5.1B-1.1)

14 As YEC only included detailed line-item cost estimate or breakdowns
15 for a subset of the capital projects described in the application, the
16 Board wishes to better understand both the role of the owners engineer
17 function and the extent to which other YEC projects described in the
18 application may have used, or expect to use, owners engineer service.

19 **QUESTION:**
20

- 21 a) Please fully explain the role of the owners engineered function in the context of
22 YEC’s administration of capital projects. In your response, please provide both a
23 high-level description of YEC’s understanding of the services provided by an
24 owners engineer and a discussion of the role that the owners engineer played in
25 the project noted in the preamble above.
26
- 27 b) The Board notes that in the project cost breakdown provided for the BESS project,
28 in Table 5.1A-7 (see Application PDF page 249), there are line items for both an
29 “owners engineer” and for “project management.” Please explain why YEC
30 determined that expenditures on both of these functions (rather than, for example,
31 only having a project manager with responsibility to ensure the prudent
32 advancement of the project) was deemed necessary in this case.
33
- 34 c) Please confirm that no other capital projects included in the application, including
35 both projects for which capital additions were made during the 2023-2024 test
36 period or projects expected to be completed in the 2025-2027 period or
37 subsequently, include either actual or forecasted expenditures on owners engineer

1 services. If this cannot be confirmed, please provide a list of all application capital
2 projects that either incurred or are forecasted to owners engineer costs. For any
3 projects so identified, please indicate the corresponding expenditure or forecast of
4 owners engineer costs.
5

6 **ANSWER:**

7
8 **(a) and (b)**
9

10 The Project Manager is responsible for the overall delivery of the project, managing scope,
11 budget, schedule, contracts, and coordination across departments. In contrast, the
12 Owner's Engineer provides independent technical oversight to ensure engineering quality,
13 technical compliance, and alignment with the owner (Yukon Energy) expectations. These
14 are fundamentally different skillsets: one ensures the project is delivered effectively, the
15 other ensures it is engineered correctly. Both are essential for prudent project
16 advancement and are normal components of major projects. For these reasons (the two
17 roles serve distinct and complementary functions), Yukon Energy included both a Project
18 Manager and an Owner's Engineer in the BESS project budget as.
19

20 The roles and responsibilities of the Owner's Engineer (OE) are described below.
21

22 Roles

- 23 • Independent Technical Advisor: Acts as a representative of the owner (Yukon
24 Energy), focusing on the technical integrity and success of the project.
- 25 • Engineering Lead: Serves as the primary technical point of contact and leads the
26 engineering efforts on behalf of the owner.
- 27 • Technical Oversight: Provides oversight and support for all technical aspects of
28 the project, ensuring they align with the owner's expectations and standards.
29

30 Responsibilities

31 Project Support:

- 32 • Acts as the main point of contact for technical activities, overseeing the
33 engineering work to ensure project specifications and quality standards are
34 met.
- 35 • Supports the project scope development, including size, location, technology,
36 SOW, and schedule, from the project's inception.

- Leads technical reviews of vendor documents and provides input on contractors' procedures and documents.

Risk Management:

- Collaborates with the Project Manager (PM) to identify, quantify, and develop strategies for mitigating technical risks.
- Ensures that all technical deliverables, from design to commissioning, align with the owner's standards and expectations.

Representation and Coordination:

- Represents the owner in various technical activities and discussions, ensuring the owner's interests are protected and advanced.
- Works under the direction and oversight of the Yukon Energy PE (Project Engineer), reporting to both the PE and PM, and ensuring transparent communication throughout the project lifecycle.

(c)

As detailed in parts (a) and (b), costs for both Project Management and Owner's Engineer are standard components of major projects. A list of all capital projects in the application that specifically referred to Owner's Engineer that either incurred or are forecasted to owners engineer costs are included below, along with the corresponding expenditure or forecast of owners engineer costs and the reference of where this can be found.

Project	Expenditures	Reference
Thermal Replacement	\$ 1,169,000	Table 5.1A-3
Battery Energy Storage System	\$ 890,000	Table 5.1A-5
Lewes River Boat Lock	\$ 225,000	Table 5.1B-2
WH3 10-Year Overhaul	\$ 100,000	Table 5.1A-38
WHS West Gate Refurbishment	Not detailed in GRA	Section 5.1B-1.3
WHS West Gate Refurbishment	Not detailed in GRA	Section 5.1B-1.5
Protection, Control and SCADA Upgrade: WH4	Not detailed in GRA	Section 5.1B-2.1
WG0 10-Year Major Plant Overhaul	Not detailed in GRA	Section 5.1B-5.6

Owner's Engineer of other projects were not specifically referred to but may be included in Contractor or Consultant project headings for simplification.

1 **REFERENCE:** Board Order 2025-12 Appendix, PDF page 11; YEC June 30, 2025
2 Response to Supplementary Information requested in Yukon
3 Utilities Board Order 2025-12, PDF page 44
4

5 **ISSUE:** YEC project naming/numbering system
6

7 **PREAMBLE:** The Board has become aware that the naming of certain YEC projects
8 has changed between GRAs, thereby potentially complicating the
9 assessment of expenditures on certain projects.
10

11 For example, the Board notes that for a request that YEC provide
12 information necessary to support the examination of variances between
13 capital project forecasts and actual capital addition amounts for projects
14 completed during the 2023-2024 test period, as set out in section 3.1.2
15 of Appendix A to Board Order 2025-12, the Board prepared a table (see
16 Table 1 at PDF 11 of Order 2025-12 Appendix) that identified a
17 generation project as “Mayo Mobile Diesel Genset,” reflecting the
18 project name used by YEC in Tables 5.3, 5.4, and 5.8 of the application.
19 However, in part of its response to information requested in section
20 3.1.2 of Board Order 2025-12 Appendix A (see PDF page 44 of YEC
21 June 30, 2025 response), the corresponding project appears to be
22 named “2023 Mayo-Faro Diesel Infrastructure”
23

24 **QUESTION:**
25

- 26 a) Please briefly describe the internal YEC capital project numbering system, if any,
27 used by YEC to ensure that accounting and other information pertaining to specific
28 projects is tracked accurately.
29
- 30 b) Please provide an update to Table 1 from the Appendix to Board Order 2025-12
31 (at PDF page 11) that includes an additional column to the left of the project names
32 that shows the applicable YEC project number.

1 **ANSWER:**

2
3 **(a)**

4
5 The Yukon Energy capital project numbering system is a manual process where new
6 projects are assigned a Project Identification (PID) Number in the format Pyr-### where:

7
8 yr = the year the PID was created; and

9 ### = sequential ordering of a PID creation each year, starting from 001.

10
11 For example, the first PID assigned in 2025 was P25-001.

12
13 Names for PID's can change if it is determined a different name is more appropriate.

14
15 **(b)**

16
17 The updated table is provided below.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-73

PID #		2023 Addition Amount	2024 Addition Amount	Total 2023-2024 Period Additions	CWIP Balance at year-end 2024?
		(\$ 000s)			
	Generation				
P17-004	Thermal Replacement (16.5)	122.4		122.4	Yes
P23-029	Mayo Mobile Diesel Genset	5,289.7	1,226.3	6,516	No
P21-010	MH0 Road & Road Slope Stability	1,762.5	44.4	1,806.9	No
P20-044	Wareham Spillway Concrete Repair		936.7	936.7	No
P22-011	Schwatka Lake Safety/Debris Boom		1,220.2	1,220.2	No
P22-004	Lewes River Boat Lock	20.4		20.4	Yes
	Other Projects with <\$400k Spending	(207.5)	1,088.9	881.4	Yes
	Generation projects subtotal	6,987.5	4,516.5	11,504.0	
	Transmission				
P21-001	Whitehorse interconnection	10,772.5	86.5	10,859	No
P23-021	P&C: S250 Callison Protection, Control and SCADA Upgrade	2158.1		2,158.1	Yes
P24-069	Load Bank & T transformers		1,722.8	1,722.8	No
P20-034	L177 Re Route	524.4		524.4	No
	Other Projects with <\$400k Spending	211.7	380.9	592.6	Yes
	Transmission projects subtotal	13,666.7	2,190.2	15,856.9	
	Distribution				
P19-016	IPP Connections	538.4	5,905.3	6,443.7	No
P04-199	Customer Extensions	152.6	2655.2	2807.8	No
P18-027	Synchronous Condenser Overhaul	991.8		991.8	No
P23-035	Dawson Distribution 3 Phase Loop	500.2		500.2	No
P17-023	Distribution Upgrades	210.9	166.7	377.6	No
	Other Projects with <\$400k Spending		27.2	27.2	Yes
	Distribution projects subtotal	2,393.9	8,754.4	11,148.3	
	General Plant				
P21-006	Whitehorse Stoplog Crane Replacement		3,323.3	3,323.3	No
P10-039	Vehicle Purchases	612.6	890.2	1,502.8	No
P20-033	Crane Refurbishment Program		115.1	115.1	No
P20-042	New Mobile Office Unit - IT	738.7		738.7	No
P11-063	SCADA Upgrade Program	18.8	18.3	37.1	No
P23-003	HQ Datacenter Server Replacement		492.2	492.2	No
P24-074	Mayo Digger		453.5	453.5	No
P09-152	Computer Replacements	61.4	138.3	199.7	No
	Other Projects with <\$400k Spending	1,410.9	1,091.8	2,502.7	Yes
	General Plant projects subtotal	2,842.4	6,522.7	9,365.1	
	Overhaul				
P22-046	AH1 10 Year Overhaul	2,337.9		2,337.9	No
P24-032	AH3 Overhaul		2,286.8	2,286.8	No
P20-038	WG3 Overhaul		453.2	453.2	No
	Other Projects with <\$400k Spending	690.5		690.5	No
	Overhaul projects subtotal	3,028.4	2,740.0	5,768.4	
	Intangible Assets				
P18-002	PAMMS Asset Management Framework	5,459.5		5,459.5	No
P23-001	Tailrace Gate Certifications		552.4	552.4	No
	Other Projects with <\$400k Spending	86.9	340.4	427.3	Yes
	Intangible asset projects subtotal	5,546.4	892.8	6,439.2	
	Deferred Costs				
P11-090	Mayo Lake Enhanced Storage		2,267.2	2,267.2	No
P22-043	DSM Program 2022-2030	1,289.2	1,101.6	2,390.8	No
	Other Projects with <\$400k Spending	994.5	952.1	1,946.6	Yes
	Deferred cost projects subtotal	2,283.7	4,320.9	6,604.6	
	Grand Total	36,749.0	29,937.5	66,686.5	

1 **REFERENCE:** YEC 2025-2027 Application PDF pages 242, 260, 274, 279, 282, 291,
2 294, 297, 299, 306, 384, 404, 405, 406, and 412

3
4 **ISSUE:** Allocation of internal YEC costs to projects

5
6 **PREAMBLE:** The Board has identified the following projects that include references
7 to allocations of YEC internal costs to projects.

- 8
9
 - Thermal Replacement (16.5 MW) project (Appendix 5.1A-1)
 - 10 • MH0 Rockslide Stabilization and Remediation project (Appendix
 - 11 5.1A-3)
 - 12 • MH0 Surge Chamber Replacement (Appendix 5.1A-5)
 - 13 • Transmission Line Refurbishment L178 (Appendix 5.1A-6)
 - 14 • Dawson Voltage Conversion (Appendix 5.1A-7)
 - 15 • Spare Power Transformer Program (Appendix 5.1A-9)
 - 16 • Dam Safety Review Mitigations (Appendix 5.1A-10)
 - 17 • WH3 Headgate Replacement (Appendix 5.1A-11) 7
 - 18 • WH3 10-Year Overhaul (Appendix 5.1A-12)
 - 19 • Lewes River Boat Lock (Appendix 5.1B-1.1)
 - 20 • WRGS Long-term Water Use Licence Renewal (Appendix 5.2A-1)
 - 21 • MGS Water Use Licence Renewal (Appendix 5.2A-3)

22
23 **QUESTION:**

- 24
25 a) Please confirm that all YEC capital projects involve some YEC internal costs and
26 all projects receive an allocation of YEC internal costs for the purposes of both the
27 preparation of project forecasts and determination of final project costs. If this
28 cannot be confirmed, please explain.
29
30 b) Please provide an explanation of the process used to determine the amount of
31 YEC internal costs that should be allocated to specific capital projects. If possible,
32 please provide any relevant internal YEC guide or document that explains how
33 internal YEC should be allocated to projects.
34
35 c) Please explain how YEC ensures that internal labour costs allocated to specific
36 capital projects are netted off when determining the amounts of internal YEC costs

1 that should be recorded to relevant operations and maintenance expense accounts
2 for specific years.

3

4 **ANSWER:**

5

6 **(a) and (b)**

7

8 All Yukon Energy capital projects will involve some Yukon Energy internal costs. However,
9 Yukon Energy believes caution should be used for the term 'allocation' for Yukon Energy
10 internal costs for the purposes of both the preparation of project forecasts and
11 determination of final project costs. In this context, Yukon Energy interprets 'allocation' as
12 a general formulaic approach rather than costs based on actual or expected actual work.
13 To be clear, there is no allocation such as a 10% charge to capital projects.

14

15 For actual costs, Yukon Energy uses a time reporting program that allows employees to
16 code their time to each of the projects, maintenance or administrative work to the nearest
17 six minutes. Actual costs of capital projects only include those hours that were coded by
18 the employee to that project; there is no 'allocation'. Coding of employee hours is reviewed
19 and approved by their supervisor.

20

21 For forecast project costs, the project manager estimates the amount of internal labour
22 hours required; there is no 'allocation'.

23

24 **(c)**

25

26 Yukon Energy ensures that actual internal labour costs charged to specific capital projects
27 are excluded from internal Yukon Energy labour costs that should be recorded to relevant
28 operations and maintenance expense accounts by the time reporting systems and the
29 coding of time as described in part (a). Labour hours can only be coded to one of capital
30 or non-capital (maintenance or administration).

31

32 The same is true of forecast internal labour costs in that the forecast labour hours can only
33 be coded to one of capital or non-capital (maintenance or administration). Details of how
34 Yukon Energy budgets and forecasts internal labour costs have been provided in Yukon
35 Energy's response to YUB-YEC-1-39(b).

1 **REFERENCE:** Board Order 2024-05 Appendix A Errata, paragraph 250; YEC
2 2025-2027 Application Section 5.4, PDF page 204, and Appendix
3 5.5A-1, PDF pages 470-471; Board Order 2025-12 Appendix A,
4 Table 1, PDF pages 11-12
5

6 **ISSUE:** 2023-2024 forecast vs. actual variance explanations
7

8 **QUOTE** At paragraph 250, Appendix A (Errata) to Board Order 2024-05 states:
9 When YEC requests these capital projects to be added to its rate base,
10 all actual costs incurred and the prudence thereof, will be examined
11 further. YEC is reminded that the Board will expect YEC to file sufficient
12 detail respecting its forecast and actual costs for each such capital
13 project and to include all variance explanations where actual costs are
14 different from those approved on a forecast basis in this Board Order.
15 [Emphasis added]
16

17 **PREAMBLE:** In Section 5.4 (PDF page 204) and Appendix 5.5A-1 of the application,
18 YEC appears to have applied a limitation that variances between
19 approved GRA forecast and actual capital project expenditures must
20 be overspends that exceed \$100,000.
21

22 The Board requests that YEC comply in full with the direction at
23 paragraph 250 of Board Order 2024-05 Appendix A (Errata). To this
24 end, the Board will require YEC to prepare brief forecast vs. actual
25 variance explanations (as described in the request below) for all
26 projects included in Table 1 from Board Order 2025-12 Appendix A.
27

28 For the purposes of this information request, please exclude the
29 following projects, which are addressed in separate IRs:
30

- 31 • Thermal Replacement (16.5 MW) project
- 32 • 2023 Mayo-Faro Diesel Infrastructure project
- 33 • Lewes River Boat Lock Road Access Rebuild project
- 34 • S250 Callison project
- 35 • Synchronous Condenser Overhaul project
- 36 • Dawson Distribution 3 Phase Loop project
- 37 • Distribution Upgrades

1 **QUESTION:**

- 2
- 3 a) Please provide a brief explanation of the reasons for the GRA forecast vs actual
4 cost variance (including variances for projects for which actual project
5 expenditures were below the approved 2023-2024 GRA forecast) for each project
6 noted in Table 1 other than those listed in the preamble above. In the response,
7 please confirm within the write-up of each project that all project elements included
8 in the GRA project cost forecast were completed. For any projects, where YEC
9 cannot confirm that all elements of the original forecast scope of the project were
10 completed, please include a brief explanation as to what elements were not
11 completed and a discussion of the reason that the reduction in project scope
12 occurred.

13

14 **ANSWER:**

15

16 **(a)**

17

18 Please see the table below that summarizes 2023/24 GRA forecast costs as compared to
19 2023 and 2024 actual costs.

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-75

	2023/24 GRA			
	Forecast	Actual	Variance	Notes
Generation				
MH0 Road & Road Slope Stability	\$ 1,874,357	\$ 1,806,855	\$ (67,501)	1
Wareham Spillway Concrete Repair	\$ 500,000	\$ 936,689	\$ 436,689	2
Schwatka Lake Safety/Debris Boom	\$ 1,096,751	\$ 1,220,249	\$ 123,498	3
Lewes River Boat Lock	\$ -	\$ 20,435	\$ 20,435	4
Transmission				
Whitehorse interconnection	\$ 11,198,851	\$ 10,859,011	\$ (339,840)	5
Load Bank & Transformers	\$ -	\$ 1,722,769	\$ 1,722,769	6
L177 Re Route	\$ 304,702	\$ 52	\$ (304,650)	7
Distribution				
IPP Connections	\$ -	\$ (213,178)	\$ (213,178)	8
Customer Extensions	\$ 666,376	\$ 460,840	\$ (205,536)	9
General Plant				
Whitehorse Stoplog Crane Replacement	\$ 4,246,677	\$ 3,323,283	\$ (923,394)	10
Vehicle Purchases	\$ 1,190,794	\$ 1,502,826	\$ 312,032	11
Crane Refurbishment Program	\$ 700,000	\$ 115,130	\$ (584,870)	12
New Mobile Office Unit IT	\$ 810,235	\$ 738,717	\$ (71,518)	13
SCADA Upgrade Program	\$ 20,000	\$ 37,049	\$ 17,049	14
HQ Datacenter Server Replacement	\$ 300,000	\$ 492,182	\$ 192,182	15
Mayo Digger	\$ -	\$ 453,500	\$ 453,500	16
Computer Replacements	\$ 150,000	\$ 199,681	\$ 49,681	17
Overhaul				
AH1 10 Year Overhaul	\$ 2,460,967	\$ 2,337,856	\$ (123,111)	18
AH3 Overhaul	\$ 2,200,000	\$ 2,286,830	\$ 86,830	19
WG3 Overhaul	\$ 400,000	\$ 453,168	\$ 53,168	20
Intangible Assets				
PAMMS Asset Management Framework	\$ 5,466,181	\$ 5,459,467	\$ (6,714)	21
Tailrace Gate Certifications	\$ 95,000	\$ 552,372	\$ 457,372	22
Deferred Costs				
Mayo Lake Enhanced Storage	\$ -	\$ 2,267,202	\$ 2,267,202	23
DSM Program 2022 2030	\$ 2,410,000	\$ 1,547,259	\$ (862,741)	24

1
2

1 Brief explanations of the reasons for the GRA forecast vs actual cost variance are as
2 follows:

- 3
4 1. **MH0 Road & Road Slope Stability** - Actual costs were slightly less than forecast
5 in the 2023/24 GRA primarily because rock blasting was not required. All project
6 elements included in the GRA project cost forecast were completed.
7
- 8 2. **Wareham Spillway Concrete Repair** - Actual costs were higher than forecast in
9 the 2023/24 GRA primarily because it was determined that additional work was
10 required to be performed in 2024. This project variance explanation was provided
11 in section 5.5A-1 on PDF page 470 of the application. The 2023/24 GRA forecast
12 assumed work would only be required in 2023. In 2024 it was determined
13 additional work was required to perform non-destructive testing and visual
14 inspection. All project elements included in the GRA project cost forecast were
15 completed.
16
- 17 3. **Schwatka Lake Safety/Debris Boom** - Actual costs were higher than forecast in
18 the 2023/24 GRA primarily because it was determined that additional work was
19 required to be performed in 2024. This project variance explanation was provided
20 in section 5.5A-1 on PDF page 470 of the application. The 2023/24 GRA forecast
21 assumed work would only be required in 2023. The boom was installed in late
22 summer 2023, however, there were a few deficiencies that were required to be
23 resolved in 2024; the boom was found to be stretched very tight so additional boom
24 sections were installed and hardware modifications completed. All project
25 elements included in the GRA project cost forecast were completed.
26
- 27 4. **Lewes River Boat Lock** – There were no costs forecast in the 2023/24 GRA.
28 Actual costs were higher than forecast in the 2023/24 GRA because there were
29 unanticipated costs to recover insurance funds.
30
- 31 5. **Whitehorse Interconnection** - Actual costs were less than forecast in the 2023/24
32 GRA primarily because the project did not incur many deficiencies, so the full
33 amount of contingency was not used. All project elements included in the GRA
34 project cost forecast were completed.
35
- 36 6. **Load Bank & Transformers** – This project was not included in the 2023/24 GRA.
37 A detailed review of this project was provided in Appendix 5.5 starting on PDF
38 page 472 of the application.

1 7. **L177 Re Route** - Actual costs were less than forecast in the 2023/24 GRA. In the
2 2023/24 GRA, the project write-up noted "The relocation work that YEC is
3 responsible for is estimated to cost \$316k and planned for completion in 2023,
4 although there is some uncertainty if YG will proceed with it." It was later
5 determined that Yukon Government did not require the work, so Yukon Energy
6 avoided the additional costs. All other project elements included in the GRA project
7 cost forecast were completed.

8
9 8. **IPP Connections** - Actual costs were less than forecast in the 2023/24 GRA. In
10 the 2023/24 GRA, it was assumed that there would be projects still in progress at
11 the end of 2024, as reflected by the closing WIP balances of both IPP connections
12 and IPP contributions. However, by the end of 2024 it was determined that there
13 were no projects that expected to proceed into 2025, so all project costs and
14 contributions were closed resulting in recognition of contributions in excess of
15 costs for the 2023/24 period (to match costs in excess of contributions for prior
16 periods). Over the full construction period of an IPP connection, the proponent is
17 responsible for all costs.

18
19 The following projects listed in the 2023/24 GRA were not completed and were
20 determined to be unlikely to continue:

- 21
22 • CTMC 2 MW Solar;
23 • NNDC 2 MW Solar;
24 • NNDC 2 MW Solar; and
25 • 250 kW Solar.
26

27 9. **Customer Extensions** - Actual costs were less than forecast in the 2023/24 GRA.
28 At the time of preparation of a GRA, the workload of customer connections is
29 unknown as it is determined by requests by the customer. Yukon Energy uses
30 historical results to try to predict future overall costs, but it is not possible to provide
31 more detailed forecasts by individual customers. Results can vary based on the
32 number of connections and the type of connection and the status of whether a
33 project is completed at year-end.
34

35 10. **Whitehorse Stoplog Crane Replacement** - Actual costs were less than forecast
36 in the 2023/24 GRA primarily because of less than expected internal labour costs
37 and unused risk contingency. Actual Yukon Energy labour was \$163,000 as

1 compared to a plan of \$518,000 due to efficiencies of interfacing with only the
2 prime contractor as compared to multiple contractors. Some of the major risks that
3 were not realized included:

- 4
- 5 a. There was concern that the existing structure had settled and would need
6 significant work to correct or possibly replace. The risk was not realized as
7 the beams could be shimmed to achieve the monorail beam alignment.
 - 8 b. The condition of existing beams was in question at the onset of the project.
9 The beams turned out to be reusable with minimal work.
- 10

11 All project elements included in the GRA project cost forecast were completed.

12

13 **11. Vehicle Purchases** - Actual costs were higher than forecast in the 2023/24 GRA
14 primarily because of unplanned purchase requirements. This project variance
15 explanation was provided in section 5.5A-1 on PDF page 470 of the application.
16 All project elements included in the GRA project cost forecast were completed.

17

18 **12. Crane Refurbishment Program** - Actual costs were less than forecast in the
19 2023/24 GRA primarily because the project did not incur as many deficiencies as
20 originally expected. All project elements included in the GRA project cost forecast
21 were completed.

22

23 **13. New Mobile Office Unit – IT** - Actual costs were less than forecast in the 2023/24
24 GRA primarily because the Unit hook up was less than anticipated. All project
25 elements included in the GRA project cost forecast were completed.

26

27 **14. SCADA Upgrade Program** - Actual costs were higher than forecast in the 2023/24
28 GRA primarily because it was determined that additional work was required to be
29 performed in 2023 and 2024. This program is normally a small \$10,000 budget but
30 the addition of Host A and Host B server replacements resulted in increased
31 spending in these years. All project elements included in the GRA project cost
32 forecast were completed.

33

34 **15. HQ Datacenter Server Replacement** - Actual costs were higher than forecast in
35 the 2023/24 GRA primarily because of more complexities than expected. This
36 project variance explanation was provided in section 5.5A-1 on PDF page 470 of
37 the application. All project elements included in the GRA project cost forecast were
38 completed.

- 1 16. **Mayo Digger** - This project was not included in the 2023/24 GRA. A detailed
2 review of this project was provided in Appendix 5.5 starting on PDF page 474 of
3 the application.
4
- 5 17. **Computer Replacements** - Actual costs were higher than forecast in the 2023/24
6 GRA primarily because of the general increasing need to replace computers more
7 frequently, and staff levels growing more quickly. All project elements included in
8 the GRA project cost forecast were completed.
9
- 10 18. **AH1 10-Year Overhaul** - Actual costs were less than forecast in the 2023/24 GRA
11 primarily because the project did not incur many deficiencies, so the full amount of
12 contingency was not used. When performing an overhaul, the amount of work to
13 be discovered when the unit is dismantled is unknown in advance. All project
14 elements included in the GRA project cost forecast were completed.
15
- 16 19. **AH3 Overhaul** - Actual costs were greater than forecast in the 2023/24 GRA
17 primarily because unexpected complexities were encountered during the
18 inspection phase, which required additional resources, and extended work hours
19 to address unforeseen adjustments. When performing an overhaul, the amount of
20 work to be discovered when the unit is dismantled is unknown in advance. All
21 project elements included in the GRA project cost forecast were completed.
22
- 23 20. **WG3 Overhaul** - Actual costs were greater than forecast in the 2023/24 GRA
24 primarily because unexpected complexities were encountered during the
25 inspection phase, which required additional resources, and extended work hours
26 to address unforeseen adjustments. When performing an overhaul, the amount of
27 work to be discovered when the unit is dismantled is unknown in advance. All
28 project elements included in the GRA project cost forecast were completed.
29
- 30 21. **PAMMS Asset Management Framework** - Actual costs were only \$6,714, or
31 0.1%, less than forecast. All project elements included in the GRA project cost
32 forecast were completed.
33
- 34 22. **Tailrace Gate Certifications** - This project was not included in the 2023/24 GRA.
35 A detailed review of this project was provided in Appendix 5.5 starting on PDF
36 page 473 of the application.

1 **23. Mayo Lake Enhanced Storage** - This project was not included in the 2023/24
2 GRA. A detailed review of this project was provided in Appendix 5.2A-4 starting on
3 PDF page 407 of the application.

4
5 **24. DSM Program 2022-2030** - Actual costs were less than forecast in the 2023/24
6 GRA primarily due to pivots made to create efficiencies in programming and
7 increased external financial contributions to the Project. All project elements
8 included in the GRA project cost forecast were completed.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 44; YEC 2023-
4 2024 GRA Application, PDF pages 157-165; YEC 2025-2027
5 Application Table 5.1A-2, PDF page 236; Section 5.4, PDF page
6 204, and Appendix 5.5A-1, PDF pages 470-471
7

8 **ISSUE:** Thermal Replacement (16.5 MW) project
9

10 **PREAMBLE:** In section 3.1.2 of the Appendix A to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to Board Order 2025-12 Appendix A were discussed in YEC's 2023-
13 2024 or prior GRAs.
14

15 In its June 30, 2025 response to the supplemental information sought
16 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
17 pages 44-48 that included a description of prior GRA references for the
18 Thermal Replacement (16.5 MW) project at PDF page 44.
19

20 YEC recorded a capital addition in 2023 for the Thermal Replacement
21 (16.5 MW) project of \$122,400 in 2023 and has forecast a final capital
22 addition in the amount of -\$62,219,700 in 2025, reflecting the remaining
23 CWIP balance of \$51,703,700 at the end of 2024, plus a further forecast
24 expenditure of \$10,516,000 in 2025. Thus, YEC's forecast of final
25 capital additions in respect of the project totals \$62,342,100 after the
26 forecast 2025 capital addition.
27

28 A breakdown of Thermal Replacement (16.5 MW) project costs
29 provided in Table 5.1A-2, found at PDF 236 of the current application,
30 indicates that the project was previously expected to have a final cost
31 of \$60,566,000.
32

33 Both YEC's 2023-2024 GRA business case and 2025-2027 business
34 case for the Thermal Replacement (16.5 MW) project indicate that a
35 capital addition in respect of the project in the amount of approximately
36 \$18,176,000 was anticipated but did not occur in practice.

1 **QUESTION:**

- 2
- 3 a) Please explain why the apparent variance of \$1,776,100 (\$62,342,100 -
- 4 \$60,566,000) between previously anticipated costs and final project costs was not
- 5 discussed in either Section 5.4 or Appendix 5.5A-1 of the application.
- 6
- 7 b) Please provide a detailed breakdown of the project cost forecast used to support
- 8 the thermal Replacement (16.5 MW) project in YEC's 2023-2024 GRA.
- 9
- 10 c) Please provide a brief explanation of forecast versus actual expenditure variances
- 11 for each of the line-items used in the 2023-2024 GRA forecast document provided
- 12 in the response to part (b) above.
- 13
- 14 d) Please explain what elements of the project were to have been completed as part
- 15 of the anticipated capital addition in the amount of \$18,176,000. Please explain the
- 16 reason that this did not occur.
- 17

18 **ANSWER:**

19

20 **(a)**

21

22 Yukon Energy acknowledges it did not specifically connect the variance to an explanation

23 in the Application, and in error did not identify the variance in either Section 5.4 or

24 Appendix 5.5A-1 of the Application.

25

26 However, in Appendix 5.1A-1 on PDF page 236 of the Application, Yukon Energy reported

27 "Due to issues identified during commissioning, however, the in-service date of the two

28 new Faro units, FD8 and FD9, was delayed, and those units were not considered in-

29 service until early 2025. As a result, the entire Thermal Replacement project was kept in

30 WIP at the end of 2024, rather than treating the Faro portion as completed and approved

31 as per the 2023/24 GRA." Table 5.1A-2 also reported on the resulting cost variance.

32

33 Due to issues discovered during the Faro commissioning stage, several scope changes

34 were required in Faro and Dawson resulting in additional project costs. Supply chain

35 disruptions, additional efforts required, engineering challenges, and the availability of

36 vendor resources significantly impacted project timelines for Faro and Dawson.

37 Additionally, the Diesel Exhaust Fluid supply system in Faro and Dawson required extra

insulation for piping and intake ports and modifications to associated piping. These are the primary reason for the variance. Another reason for the overall project variance is the project scope in Whitehorse now requires a Fuel system, which was not originally included.

(b) and (c)

A detailed breakdown of the project cost forecast used to support the thermal Replacement (16.5 MW) project in Yukon Energy's 2023-2024 GRA has been provided below, alongside the forecast provided in Table 5.1A-3 of the application.

Category	2023/24 GRA Forecast	2025-2027 GRA Forecast	Variance
EPC Contractor - Faro	15,180	16,065	885
EPC Contractor - Dawson	21,305	22,498	1,193
EPC Contractor - Whitehorse	14,195	14,740	545
Station Service Supply (Faro & Dawson)	450	877	427
YEC Internal Cost	1,185	1,157	(28)
Owner's Engineer (BBA)	655	1,020	365
Feasibility & Engineering	162	122	(40)
Assessment & Permitting	290	432	142
Communication & Public Engagement	180	153	(27)
First Nation Engagement	100	30	(70)
Fuel (Onsite Commissioning)	890	801	(89)
AFUDC	1,710	2,369	659
Subtotal	56,302	60,264	3,962
Contingency	2,308	0	(2,308)
Total Stagegate 1, 2, 3	1,956	1,956	0
Overall Project Total	60,566	62,220	1,654

Explanations for variances are as follows:

- **EPC Contractor for Faro/Dawson/Whitehorse:** Increases for additional commissioning requirements and scope changes as described in part (a).

- 1 • **Station Service Supply:** Unexpected ground grid substation upgrades to enhance
2 safety in Faro and Dawson led to higher costs.
3
- 4 • **Owners Engineer:** Extended project timelines and additional changes increased
5 owners engineer involvement, surpassing initial estimates.
6
- 7 • **Assessing and Permitting:** Greater-than-expected costs tied to YESAB
8 application efforts and other permits required.
9
- 10 • **AFUDC:** Increased due to project schedule adjustments.
11
- 12 • **Contingency:** Most contingency-based items materialized, along with some
13 unplanned ones. Therefore, all contingency funds have been depleted.
14

15 Uncertainties remain regarding foundation improvements and fuel systems at the
16 Whitehorse site, potentially requiring additional funding in the future.

17
18 **(d)**
19

20 The Faro units were expected to be fully commissioned and in-service by the end of 2024
21 at a total cost of \$18,176,000. Due to issues identified during commissioning, however,
22 the in-service date of the two new Faro units, FD8 and FD9, was delayed. As a result, the
23 entire Thermal Replacement project was kept in WIP at the end of 2024, rather than
24 treating the Faro portion as completed and approved as per the 2023/24 GRA. As detailed
25 in Yukon Energy's response to YUB-YEC-1-65, this is consistent with IAS 16 paragraph
26 55 which states "Depreciation of an asset begins when it is available for use, i.e., when it
27 is in the location and condition necessary for it to be capable of operating in the manner
28 intended by management." At the end of 2024, the Faro units were not capable of
29 operating in the manner intended by management.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 44; YEC 2023-
4 2024 GRA Application, PDF 166-167; YEC 2025-2027 Application
5 Section 5.4, PDF page 204 and Appendix 5.5A- 1, PDF pages 470-
6 471

7
8 **ISSUE:** 2023 Mayo-Faro Diesel Infrastructure project
9

10 **PREAMBLE:** In section 3.1.2 of Appendix A to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to Board Order 2025-12 Appendix A were discussed in YEC's 2023-
13 2024 or prior GRAs.
14

15 Table 1 included a reference to a project called "Mayo Mobile Diesel
16 Genset," reflecting the name of project included the 2023-2027 period
17 CWIP continuity schedule filed in the application (Table 5.8). In its June
18 30, 2025 response to the supplemental information sought in Order
19 2025-12 Appendix, YEC provided a Table at PDF pages 44-48 that
20 included a description of prior GRA references for a project called the
21 "2023 Mayo-Faro Diesel Infrastructure project." The Board understands
22 that the names "Mayo Mobile Diesel Genset" and "2023 Mayo-Faro
23 Diesel Infrastructure" are referencing the same project. As a result, the
24 Board understands that the actual capital addition amounts for the
25 Mayo Mobile Diesel Genset as noted in YEC's Table 5.8 from the
26 application (capital additions of \$5,289,700 and \$1,226,300 for the
27 years 2023 and 2024, respectively totalling \$6,516,000) can be
28 compared against the forecast for the 2023 Mayo-Faro Diesel
29 Infrastructure project.
30

31 Section 5.1A-2 at PDF pages 166-167 from YEC's 2023-2024 GRA
32 (referenced at PDF page 44 of YEC's June 30th response) indicates
33 that the 2023 Mayo- Faro Diesel Infrastructure Project was forecast to
34 cost approximately \$4,300,000 and would be completed in 2023.

1 **QUESTION:**

2
3 a) Please explain why the apparent variance of \$2,216,000 (\$6,516,000 -
4 \$4,300,000) between the 2023-2024 GRA project forecast and actual 2023-2024
5 period costs, was not discussed in either Section 5.4 or Appendix 5.5A-1 of the
6 application.

7
8 b) Please provide a detailed breakdown of the \$4,300,000 cost forecast used to
9 support the 2023 Mayo-Faro Diesel Infrastructure project in YEC's 2023-2024
10 GRA.

11
12 c) Please provide a brief explanation of forecast vs. actual expenditure variances for
13 each of the line-items used in the 2023-2024 GRA forecast document provided in
14 the response to part (b) above.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The variance was not discussed in the referenced sections due to an oversight when the
21 information was prepared for the Application.

22
23 **(b) and (c)**

24
25 Due to multiple components of this project, the variance explanation has been split into
26 two sections.

27
28 The project was originally anticipated to be completed in 2023. A detailed breakdown of
29 the project cost forecast used to support the 2023 Mayo-Faro Diesel Infrastructure project
30 in Yukon Energy's 2023-2024 GRA has been provided below alongside the 2023 forecast
31 for the project included in the 2025-2027 application.

1

Table 1: Mayo Secondary Site (\$000's)

Task	2023 Costs 2023/24 GRA Forecast	2023 Costs 2025-2027 GRA Forecast	2023 Variance
YEC Internal Cost	548	760	212
External Engineering	548	589	41
Materials	1097	1012	(85)
Construction	1462	2899	1,437
AFUDC	0	30	30
Subtotal	3,655	5,290	1,635
Contingency	645	0	(645)
Overall Project Total	4,300	5,290	990

2

3 Variances for 2023 from the original forecast are explained below:

4

5 • **Internal Costs:** Yukon Energy employees from engineering, operations and
6 planning have been involved in the design and construction of the Mayo secondary
7 rental site. Unexpected challenges leading to higher internal costs include the
8 condition of existing infrastructure, lack of accurate drawings requiring extensive
9 site verification and managing multiple contractors. Delays in linework also forced
10 Yukon Energy powerline technicians to perform a significant amount of work and
11 commissioning activities in order to meet the schedule.

12

13 • **Materials:** Costs of most components are significantly higher than Yukon Energy
14 had seen before. The tight timelines for supply on this project reduce the number
15 of suppliers Yukon Energy could use and further increased the costs. Some
16 materials were purchased through the contractor and included as construction
17 costs.

18

19 • **Construction:** Yukon Energy awarded multiple contracts for each scope of work
20 to keep the rental project on track. Each contractor added to the mobilization costs
21 and accommodation costs.

22

23 With the addition of two diesel engines in Faro as part of the Thermal Replacement project,
24 costs were incurred in 2024 to relocate and reinstall rental units around the new

permanent engines. A detailed breakdown of the project cost forecast used to support the 2023 Mayo-Faro Diesel Infrastructure project in Yukon Energy's 2023-2024 GRA has been provided below alongside the 2024 forecast for the project included in the 2025-2027 application.

Table 2: Faro Infrastructure

(\$000's)

Task	2023/24 GRA Forecast	2024 Costs 2025-2027 GRA Forecast	2024 Variance
YEC Internal Cost	0	6	6
External Engineering	0	0	0
Materials	0	15	15
Construction	0	1,206	1,206
AFUDC	0	-	0
Subtotal	0	1,226	1,226
Contingency	0	-	0
Overall Project Total	0	1,226	1,226

Work included in 2024:

- Demolish piping and MV cabling near rental tanks;
- Drain, demolish and dispose of existing piping to 1-million-liter tank;
- Remove two rental tanks;
- Install a rental tank;
- Rebuilding piping and pipe rack;
- Replace old solenoid valves with motorized ball valves;
- Re-run MV cabling on new cable tray;
- Demolish intake hoods on FD1 building;
- Remove YM20 and 21/store offsite until fall/reinstall and interconnect/commission;
- Re-commission fuel system;
- Update permit/inform Fire Marshall of modifications to existing fuel system; and
- Update drawings and records.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 45; YEC 2023-
4 2024 GRA Application, PDF page 183; YEC 2025-2027 Application
5 Section 5.4, PDF page 204 and Appendix 5.5A- 1, PDF pages 470-
6 471

7
8 **ISSUE:** Lewes River Boat Lock Road Access Rebuild project
9

10 **PREAMBLE:** In section 3.1.2 of Appendix A to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to Board Order 2025-12 Appendix A were discussed in YEC's 2023-
13 2024 or prior GRAs.

14
15 In its June 30, 2025 response to the supplemental information sought
16 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
17 pages 44-48 that included a description of prior GRA references for the
18 Lewes River Boat Lock Road Access Rebuild project.

19
20 YEC recorded a capital addition in 2023 for the Lewes River Boat Lock
21 Road Access Rebuild project of \$20,400 in 2023, and has forecast a
22 final capital addition in the amount of \$1,640,100 in 2025 reflecting the
23 remaining CWIP balance of \$1,440,100, plus a further forecast
24 expenditure of \$200,000 in 2025. Thus, YEC's forecast of final capital
25 additions in respect of the project totals \$1,660,500 after the 2025
26 capital addition.

27
28 Section 5.1A-13 at PDF page 183 from YEC's 2023-2024 GRA
29 (referenced at PDF page 45 of YEC's June 30, 2025 response)
30 indicates that the Lewes River Boat Lock Road Access Rebuild project
31 was forecast to cost approximately \$1,200,000 and would be
32 completed in 2024.

33 **QUESTION:**
34

- 35 a) Please explain why the apparent variance of \$460,500 (\$1,660,500 - \$1,200,000)
36 between the 2023-2024 GRA project forecast and the anticipated final cost was
37 not discussed in either section 5.4 or Appendix 5.5A-1 of the application.

1 b) Please provide a detailed breakdown of the \$1,200,000 cost forecast used to
2 support the Lewes River Boat Lock Road Access Rebuild project in YEC's 2023-
3 2024 GRA.

4
5 c) Please provide a brief explanation of forecast vs. actual expenditure variances for
6 each of the line-items used in the 2023-2024 GRA forecast document provided in
7 the response to part (b) above.

8
9 **ANSWER:**

10
11 **(a) to (c)**

12
13 Yukon Energy is not forecasting capital additions of \$1,660,500 on the Lewes River Boat
14 Lock *Road Access Rebuild* project.

15
16 The \$1,640,100 addition in 2025 is for a separate project, the Lewes River Boat Lock;
17 there is a distinction between the *Road Access* project and the Boat Lock itself. Details
18 of the addition for the Lewes River Boat Lock are provided in section 5.1B-1.1 of the
19 Application starting on PDF page 301.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 45; YEC 2023-
4 2024 GRA Application, PDF page 173; YEC 2025-2027 Application
5 Section 5.4, PDF 204 and Appendix 5.5A-1, PDF pages 470-471
6

7 **ISSUE:** P&C: S250 Callison Protection, Control and SCADA Upgrade project
8 (S250 Callison project)
9

10 **PREAMBLE:** In section 3.1.2 of Appendix A to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to Board Order 2025-12 Appendix A were discussed in YEC's 2023-
13 2024 or prior GRAs.
14

15 In its June 30, 2025 response to the supplemental information sought
16 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
17 pages 44-48 that included a description of prior GRA references for the
18 S250 Callison project.
19

20 YEC recorded a capital addition in 2023 for the S250 Callison project
21 of \$2,158,100 in 2023, and has forecast a final capital addition in the
22 amount of \$220,300 in 2025 resulting from the capitalization reflecting
23 the remaining (year-end 2024) CWIP balance of \$220,300 and despite
24 no additional expenditures being anticipated in 2025. Thus, YEC's
25 forecast of final capital additions in respect of the project totals
26 \$2,378,400 after the 2025 capital addition.
27

28 Section 5.1A-6 at PDF page 173 from YEC's 2023-2024 GRA
29 (referenced at PDF page 45 of YEC's June 30, 2025 response)
30 indicates that the S250 Callison project was forecast to cost
31 approximately \$2.125 million and would be completed in 2023.
32

33 **QUESTION:**
34

- 35 a) Please explain why the apparent variance of \$253,400 (\$2,378,400 – \$2,125,000),
36 between the 2023-2024 GRA project forecast and the anticipated final cost, was
37 not discussed in either Section 5.4 or Appendix 5.5A-1 of the application.

1 b) Please provide a detailed breakdown of the \$2.125 million cost forecast used to
2 support the S250 Callison project in YEC's 2023-2024 GRA.

3
4 c) Please provide a brief explanation of forecast versus actual expenditure variances
5 for each of the line-items used in the 2023-2024 GRA forecast document provided
6 in the response to part (b) above.

7
8 **ANSWER:**

9
10 **(a)**

11
12 As shown in Table 5.2B on PDF page 210 of the Application, the amount approved and
13 included in rate base in the 2023/24 GRA for the S250 Callison project was \$2.125 million.
14 As per Table 5.3 on PDF page 213 of the Application, the actual cost added to Yukon
15 Energy's rate base in 2023 was \$2.158 million, a difference of \$0.033 million. The
16 remaining portion of the variance was in WIP. This project was not discussed in either
17 Section 5.4 or Appendix 5.5A-1 of the application as the variance added to rates was less
18 than \$100,000.

19
20 **(b) and (c)**

21
22 A detailed breakdown of the project cost forecast used to support the project in Yukon
23 Energy's 2023-2024 GRA has been provided below, alongside the forecast provided in
24 this Application with the additional work in 2024.

Category	(\$000's)		
	2023/24 GRA Forecast	2025-2027 GRA Forecast	Variance
YEC Internal Costs	89	209	120
Other Contractors - Construction Manager	110	275	165
Prime Contractor	1,138	1,058	(80)
Materials	287	361	74
S250 Diesel (Substation Outage)	440	232	(208)
ArcFlash Damage Investigation	-	4	4
AFUDC	15	23	8
Subtotal	2,079	2,162	83
Contingency	46	217	171
Total	2,125	2,379	254

Explanations for variances are as follows:

- Yukon Energy internal costs exceeded the budget as more work was requested from staff to prepare and execute the switching required to island Dawson. There was also improvement work done on the distribution system to feed Hunker from the downtown diesel plant while the Callison substation was bypassed and out-of-service for the upgrade. In addition, the Callison P&C Upgrade project is the foundation for all the projects lined for execution in Dawson and Callison. More work was needed to upgrade the communication infrastructure at the downtown diesel plant and Callison substation for this project, Callison Synchronous Condenser, and the Thermal Replacement project.
- The forecast for the External Construction Manager exceeded the budget estimate and was the result of adding other small external contractors to this line item, such as automation support at the substation and the diesel plant and further Engineering support. Other contractors included network support and procurement support.
- Materials were higher than the estimated budget due to low estimates from the consultant.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 46; YEC 2023-
4 2024 GRA Application, PDF page 212; YEC 2025-2027 Application
5 Section 5.4, PDF page 204 and Appendix 5.5A- 1, PDF pages 470-
6 471

7
8 **ISSUE:** Synchronous Condenser Overhaul project
9

10 **PREAMBLE:** In section 3.1.2 of the Appendix to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to Board Order 2025-12 Appendix A were discussed in YEC's 2023-
13 2024 or prior GRAs.
14

15 In its June 30, 2025 response to the supplemental information sought
16 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
17 pages 44-48 that included a description of prior GRA references for the
18 Synchronous Condenser Overhaul project.
19

20 YEC recorded a capital addition in 2023 for the Synchronous
21 Condenser Overhaul project of \$991,800 in 2023. Section 5.1B-3 at
22 PDF page 212 from YEC's 2023-2024 GRA (referenced at PDF page
23 46 of YEC's June 30th response) indicates that the Synchronous
24 Condenser Overhaul project was forecast to cost approximately
25 \$616,000, and would be completed in 2023.

26 **QUESTION:**
27

28 a) Please explain why the apparent variance of \$375,800 (\$991,800 – \$616,000)
29 between the 2023-2024 GRA project forecast and the final cost, was not discussed
30 in either Section 5.4 or Appendix 5.5A-1 of the application.
31

32 b) Please provide a detailed breakdown of the \$616,000 million cost forecast used to
33 support the Synchronous Condenser Overhaul project in YEC's 2023-2024 GRA.
34

35 c) Please provide a brief explanation of forecast versus actual expenditure variances
36 for each of the line-items used in the 2023-2024 GRA forecast document provided
37 in the response to part (b) above.

ANSWER:

(a)

The variance was not discussed in the referenced section due to an oversight when the information was prepared for the Application.

(b) and (c)

A detailed breakdown of the 2023/24 GRA forecast cost as compared to the actual expenditures in the current application is below.

Category	2023/24 GRA Forecast	2025-2027 GRA Forecast	Variance
Station Service Supply	0	299	299
YEC Internal Cost	25	47	22
Materials	215	191	(24)
Contractors	368	439	71
AFUDC	8	16	8
Overall Project Total	616	992	376

The variance resulted from the original forecast not considering diesel fuel charges that would be allocated to the capital project.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF pages 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF page 46; YEC 2023-
4 2024 GRA Application, PDF page 212; YEC 2025-2027 Application
5 Section 5.4, PDF page 204 and Appendix 5.5A- 1, PDF pages 470-
6 471

7
8 **ISSUE:** Dawson Distribution 3 Phase Loop (Dawson Loop) project
9

10 **PREAMBLE:** In Section 3.1.2 of Appendix A to Board Order 2025-12, the Board
11 sought additional information about where projects described in Table
12 1 to the Board Order 2025-12 Appendix A were discussed in YEC's
13 2023-2024 or prior GRAs.

14 In its June 30, 2025 response to the supplemental information sought
15 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
16 pages 44-48 that included a description of prior GRA references for the
17 Dawson Loop project.

18 YEC recorded a capital addition in 2023 for the Dawson Loop project
19 of \$500,200 in 2023. Section 5.1B-3 at PDF page 212 from YEC's
20 2023-2024 GRA (referenced at PDF page 46 of YEC's June 30th
21 response) indicates that the Dawson Loop project was forecast to cost
22 approximately \$350,000 and would be completed in 2023.
23

24 **QUESTION:**
25

26 a) Please explain why the apparent variance of \$150,200 (\$500,200 – \$350,000)
27 between the 2023-2024 GRA project forecast and the final cost, was not discussed
28 in either section 5.4 or Appendix 5.5A-1 of the application.
29

30 b) Please provide a detailed breakdown of the \$350,000 million cost forecast used to
31 support the Dawson Loop project in YEC's 2023-2024 GRA.
32

33 c) Please provide a brief explanation of forecast versus actual expenditure variances
34 for each of the line items used in the 2023-2024 GRA forecast document provided
35 in the response to part (b) above

ANSWER:**(a)**

The variance was not discussed in the referenced sections due to an oversight when the information was prepared for the Application.

(b) and (c)

A detailed breakdown of the 2023/24 GRA forecast cost as compared to the actual expenditures in the current application is below.

Category	2023/24 GRA Forecast	2025-2027 GRA Forecast	Variance
Station Service Supply	0	0	0
YEC Internal Cost	50	48	(2)
Materials	100	160	60
Contractors	200	290	90
AFUDC	0	2	2
Overall Project Total	350	500	150

The variance resulted from materials and contractor costs being greater than anticipated.

1 **REFERENCE:** Board Order 2025-12 Appendix, Table 1, PDF page 11-12; YEC
2 June 30, 2025 Response to Supplementary Information requested
3 in Yukon Utilities Board Order 2025-12, PDF pages 46 and 48; YEC
4 2025-2027 Application Section 5.4, PDF 204 and Appendix 5.5A-1,
5 PDF pages 470-471
6

7 **ISSUE:** Distribution Upgrades
8

9 **PREAMBLE:** In Section 3.1.2 of Appendix A to Board Order 2025-12, the Board
10 sought additional information about where projects described in Table
11 1 to the Board Order 2025-12 Appendix A were discussed in YEC's
12 2023-2024 or prior GRAs.

13 In its June 30, 2025 response to the supplemental information sought
14 in Board Order 2025-12 Appendix A, YEC provided a Table at PDF
15 pages 44-48 that included a description of prior GRA references
16 Distribution Upgrade expenditures. However, YEC did not provide a
17 specific 2023-2024 GRA reference for Distribution Upgrade
18 expenditures and, instead, referred to "Note 1." The text of Note 1
19 states: "The project was included in previous GRAs under the grouped
20 line item with expenditures under \$100,000."

21 YEC's 2023-2027 CWIP continuity schedule (Table 5.8) indicates that
22 actual YEC capital additions for Distribution Upgrades were \$210,900
23 in 2023 and \$166,700 in 2024 (totalling \$377,600).

24 Given that Distribution Upgrade expenditures were classified as being
25 part of grouped expenditures under \$100,000, this implies that YEC
26 expenditures on Distribution Upgrades during 2023-2024 exceeded
27 YEC's GRA forecast by at least \$277,600 (\$377,600-\$100,000).
28

29 **QUESTION:**
30

31 a) Please explain why the apparent variance of at least \$277,600 between the 2023-
32 2024 GRA project forecast and the final cost, was not discussed in either section
33 5.4 or Appendix 5.5A-1 of the application.
34

35 b) Please provide the YEC Distribution Upgrades cost forecast used to support
36 Distribution Upgrade expenditures forecast in YEC's 2023-2024 GRA.

ANSWER:

(a)

The total of Distribution Upgrades included in the 2023/24 GRA was \$200,000, resulting in a variance of \$177,600 over the two years. As these projects are completed and closed each year, the variance each year for each project was not discussed in the referenced sections due to the variance in each year being less than \$100,000 minimum Yukon Energy had assumed for its reporting on this matter.

(b) and (c)

A detailed breakdown of the 2023/24 GRA forecast cost as compared to the actual expenditures in the current application is below.

Category	2023/24 GRA Forecast	2025-2027 GRA Forecast	Variance
YEC Internal Cost	43	67	24
Materials	83	155	72
Contractors	71	152	81
Contingency	3	0	(3)
AFUDC	0	4	4
Overall Project Total	200	378	178

The variance resulted from materials and contractor costs being greater than anticipated. The amount of work required each year is increasing, resulting in the annual budget being increased from \$100,000 to \$150,000 as detailed in section 5.1B-3.5 in the application on PDF page 339.

1 **REFERENCE:** YEC 2025-2027 Application, Major Deferred Project Costs, PDF
2 pages
3 384, 394, 404 and 412-413
4

5 **ISSUE:** Activities and costs associated with cost categories
6

7 **PREAMBLE:** In the following table, the Board has accumulated YEC's description,
8 where provided, of the activities related to the cost categories for the
9 project identified along with the total costs allocated to that cost
10 category.
11

12 There appears to be a lack of clarity with respect to the quantum of
13 costs for the activities being accumulated within a given cost category.
14 For example, within the cost category of Engagement, the costs range
15 from being related primarily to catering to being costs for a legal
16 consultant. In another example, it is not clear which cost categories
17 contain YEC labour costs, notwithstanding that the cost category of
18 "YEC Internal Costs and Project Management" has identified some
19 amount of YEC labour costs.

Whitehorse Rapids Generating Station (WRGS) Table 5.2A-2, PDF page 384	Aishihik Generating Station (AGS) Relicensing Project Table 5.2A-5, PDF page 394	Mayo Generating Station (MGS) – Five-Year Renewal Costs Table 5.2A-10, PDF page 404	Mayo Lake Enhanced Storage Project (MLESF) Table 5.2A-14, PDF pages 412-413
Assessment:	Assessment & Permitting	Assessment:	Assessment:
Costs include creating the TWG's Terms of Reference, completing technical field studies, and developing the YESAA project proposal, the 60-day and 20-year YWB water use licence applications, and the FAA, as well as participation in those assessment and permitting processes (e.g., responses to information requests, providing supplementary materials, and participating in the public hearing).	not provided	Costs cover the project management consultant(s) who coordinate the TWG, and support meetings, technical reviews and manages actions. They also handle reporting, budgeting, procurement, and permitting for the project. Additionally, costs include developing the YESAA project proposal, completing technical field studies and water use licence application and FAA related expenses.	Costs include conducting the environmental and socio-economic baseline studies to support assessment and permitting, development and First Nation/public engagement of the YESAA project proposal, completing development of mitigation, monitoring and adaptive management plans, and public and FNNND engagement costs.
Total Assessment costs per Table 5.2A-2 \$6.092 million	Total Assessment and Permitting costs Table 5.2A-5 \$8.962 million	Total Assessment costs per Table 5.2A-10 \$3.062 million	Total Assessment costs per Table 5.2A-14 \$1.189 million
Project Management:	Project Management	Project Management	Project Management:
Costs cover the project management consultant(s) who coordinate the SOG and TWG, support meetings	not provided	Not provided	Costs include internal labour representing staff leadership, participation, and support for activities in

1

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-83

with planning logistics, meeting facilitation and documentation, provide technical reviews of project materials, and manage delivery of group actions. They also handle reporting, budgeting, and procurement for WRGS Relicensing.			the preceding categories (i.e., project management, assessment, engagement and third-party engineering).
Total Project Management costs per Table 5.2A-2 \$0.736 million	Total Project Management costs Table 5.2A-5 \$0.991 million	Total Project Management costs per Table 5.2A-10 \$0.017 million	Total Project Management costs per Table 5.2A-14 \$0.140 million
Engagement	Engagement	Engagement	Engagement
Costs involve facility rentals, catering and supplies for SOG meetings and TWG meetings, legal consultants for energy agreement negotiations, legal fees for advice throughout the assessment and permitting process, community engagement events and public engagement materials. Included in Engagement are costs related to the process and payments for individual and community compensation required under the Waters Act (Yukon) and other negotiated benefits to First Nations included in the Energy Agreements.	not provided	Costs involve facility rentals, catering and supplies for SOG meetings and TWG meetings, legal consultants for energy agreement negotiations, legal fees for advice throughout the assessment and permitting process, community engagement events and public engagement materials. Included in engagement are costs related to the process and payments for individual and community compensation required under the Waters Act (Yukon), and other negotiated benefits to First Nations included in the Energy Agreement or other similar instrument.	Costs include support from a legal consultant and support for negotiations with FNNND. The consultant(s) hired to assist with the assessment aided in the facilitation of the public and FNNND engagement; other engagement costs are reflected in the assessment category.
Total Engagement costs per Table 5.2A-2 \$2.786 million	Total Engagement costs Table 5.2A-5 \$3.010 million	Total Engagement costs per Table 5.2A-10 \$1.047 million	Total Engagement costs per Table 5.2A-14 \$0.021 million
n/a	n/a	n/a	Third Party Engineering
n/a	n/a	n/a	Costs include consultant costs related to the Mayo Lake outlet channel. They represent the examination of the outlet channel for capacity, determining the mechanisms for sediment recruitment and transport, a functional level design for

1

Yukon Energy Corporation
2025-27 General Rate Application
YUB-YEC-1-83

			dredging and dredgeate disposal, geophysical and bathymetric surveys, installation, maintenance, and operation of a meteorological station, and some components of the aquatic baseline program focused on the lake outlet species and habitats.
n/a	n/a	n/a	Total Third Party Engineering costs per Table 5.2A-14 \$0.458 million
Yukon Energy Internal Costs	n/a	Yukon Energy Internal Costs	Yukon Energy Internal Costs
Costs consist of Yukon Energy staff labour, travel and meal expenses, and support for activities in the preceding categories (i.e., project management, assessment, and engagement).	n/a	Costs consist of Yukon Energy staff labor, travel and meal expenses and facility rentals for public engagement events, as well as staff leadership, participation, and support for activities in the preceding categories (i.e., project management, assessment and engagement).	Internal cost made up of travel, meal expenses, and venue rentals for public engagement events.
Total YEC Internal costs per Table 5.2A-2 \$0.377 million	n/a	Total YEC Internal costs per Table 5.2A-10 \$0.547 million	Total YEC Internal costs per Table 5.2A-14 \$0.198 million
Total YEC AFUDC per Table 5.2A-2 \$0.617 million	Total AFUDC per Table 5.2A-5 \$2.205 million	Total AFUDC per Table 5.2A-10 \$0.286 million	Total AFUDC per Table 5.2A-14 \$0.261 million
n/a	Total Contingency costs per Table 5.2A-5 \$0.135 million	n/a	n/a
Total costs all categories per Table 5.2A-2 \$10.608 million	Total costs all categories per Table 5.2A-5 \$15.302 million Note: These costs are the total of all 3-years, 5-year and long-term licence). The actual and forecast costs for the AGS 25-year license renewal of \$9.770 million can be found in Table 5.2A-2 on PDF page 385.	Total costs all categories per Table 5.2A-10 \$4.959 million Note: excludes portion of costs transferred from Mayo Lake Enhanced Storage Project (MLESF)	Total costs all categories per Table 5.2A-14 \$2.267 million Note: excludes portion of costs transferred to Mayo Generating Station (MGS) – Five-Year Renewal Costs)

QUESTION:

- a) As a project proceeds, what oversight does YEC undertake to ensure the costs incurred are required, reasonable, and being allocated to the correct cost category?

1 For the following IR parts specific to the AGS relicensing project, YEC should provide
2 the requested information by cost category as requested but only related to the portion
3 of the costs specific to the AGS 25-year licence renewal (in a total amount of \$9.770
4 million which was not broken down by cost category in Table 5.2A-2).

5
6 For the three other projects, cost information provided by YEC accords with the cost
7 category and, therefore, the provided total cost information can be further detailed as
8 requested:

9
10 b) Based on the descriptions provided within each cost category for each of the four
11 projects, please provide a breakdown of the costs for each of the main activities
12 identified within the cost category.

13
14 c) Please provide additional information on YEC's engagement program with respect
15 to how "costs related to the process and payments for individual and community
16 compensation required under the Waters Act (Yukon), and other negotiated
17 benefits to First Nations included in the Energy Agreement" are determined.

18
19 d) Referring to the responses to part (b) and (c), in light of YEC's proposed increase
20 in employee complement (of approximately 25 FTEs), please identify which of the
21 costs identified as stemming from the use of consultants could, in the future, be
22 performed by one or more of the proposed new employees.

23
24 **ANSWER:**

25
26 **(a)**

27
28 As a project proceeds, Yukon Energy attempts to ensure that costs incurred are required,
29 reasonable and allocated to the correct cost category in several ways. First, as described
30 in Yukon Energy's response to YUB-YEC-1-74, labour costs are coded by the employee
31 to the nearest six minutes to the various projects being worked on, and these labour
32 charges are reviewed and approved by their supervisor.

33
34 External purchases or contractor work is done through Yukon Energy's workorder system.
35 The process includes creation of a purchase order by an employee, approval by the project
36 manager and approval of the coding by a procurement specialist.

1 On an ongoing basis, the project manager reviews costs charged to their projects. Project
2 reviews and forecast updates are done on a monthly basis. On a quarterly basis, project
3 reports are provided to the Board for their review.

4
5 Yukon Energy acknowledges that there has been some inconsistency over the years in
6 how costs are recorded and reported for licencing projects. The primary reason was that
7 categorization of different costs was at the discretion of the Project Manager, and Project
8 Managers can have differing preferences on what categorization works best for them
9 individually.

10
11 More recently, Yukon Energy has started hiring Capital Financial Analysts in various
12 departments to assist with improving accuracy and consistency of reporting going forward,
13 starting with a Capital Projects Financial Analyst in the Engineering department in late
14 2021, followed by a Regulatory Planner Financial Analyst in the Planning department in
15 2022 and finally a Financial Analyst in the Operations department in 2025.

16
17 **(b)**

18
19 The requested information is provided in the table below:

(\$ millions)	WRGS	AGS	MGS	MLESP
Assessment	6.092	6.232	3.062	1.189
TWG Terms and Conditions	0.050	-	-	-
Field Studies	1.710	2.331	0.242	0.412
Project Proposal	2.352	1.157	0.002	0.492
Water Board	1.710	0.795	-	-
FAA	0.100	0.158	-	-
MAMP	0.170	0.820	-	0.231
FNNND Engagement	-	-	-	0.054
YEC Internal Cost	-	0.316	-	-
Legal Support	-	0.523	-	-
PM Consultant	-	-	2.818	-
Project Management	0.735	0.524	0.017	0.140
PM consultant	0.712	0.195	-	-
Internal PM Labour	-	-	-	0.140
YEC Internal Cost	-	0.279	-	-
Legal Support for PM	0.023	-	0.017	-
Engagement	2.786	2.269	1.047	0.021
TWG/SOG Meetings	1.348	0.145	0.159	-
Legal	0.449	0.262	0.349	0.021
Citizen and Public Eng (Events)	0.057	0.117	0.047	-
Coms Materials	0.072	0.037	0.041	-
Compensation	0.860	1.572	0.450	-
YEC Internal Cost	-	0.136	-	-
YEC Internal Cost	0.377	-	0.547	0.198
Labour	0.341	-	0.499	-
Materials/Supplies	0.016	-	0.002	0.017
Travel / Meals	0.015	-	0.045	0.019
Rental	0.007	-	0.001	0.003
General	-	-	-	0.154
Fuel & Util	-	-	-	0.005
Third Party Engineering	-	-	-	0.458
Goephysical Survey	-	-	-	0.083
Functional Design Channel Excavation	-	-	-	0.264
Mayo Lake Erosion Study	-	-	-	0.053
Aquatic Baseline Program	-	-	-	0.058
AFUDC	0.617	0.610	0.286	0.261
Contingency	-	0.135	-	-
TOTAL	10.608	9.770	4.959	2.267

1
2

1 (c)

2
3 Before the Yukon Water Board (YWB) issues or renews a Water Use Licence under the
4 Yukon *Waters Act*, the YWB is required to ensure that compensation it considers
5 appropriate has been or will be paid by the applicant to any claimants with valid
6 compensation claims as described in subsections 12(4) and (5) of the Act who will be
7 adversely affected by the applicant's use of water under the proposed licence. This may
8 include compensation for individual claimants and/or community compensation for First
9 Nation claimants with valid claims.

10
11 When determining appropriate compensation, the YWB is required to consider all relevant
12 factors, including the following matters set out in subsection 12(5) of the *Waters Act*:

- 13
14 • Provable and/or potential loss or damage;
15
16 • The extent and duration of the adverse effect, including the incremental adverse
17 effect;
18
19 • The extent of the use of waters by persons who would be adversely affected; and
20
21 • Nuisance, inconvenience and noise.
22

23 The YWB has also established Compensation Guidelines to further assist in determining
24 appropriate compensation under the *Waters Act*,⁵ and the YWB may be guided further by
25 its own past precedent, including the YWB prior adjudication of compensation claims in its
26 Reasons for Decision for the renewals of the Aishihik Generating Station (AGS) Water
27 Use Licence both in 2002⁶ and 2023.⁷

28
29 Individual Compensation:

30 It has been Yukon Energy practice in YWB relicensing proceedings to initiate and
31 complete its own individual compensation claim process consistent with its understanding
32 of the requirements of the *Waters Act* and YWB practices. The process provides an
33 opportunity for individuals who believe they will be adversely affected by the use of water

⁵ YWB Compensation Guidelines, May 2018: <https://yukonwaterboard.ca/sites/default/files/2022-09/Guide-Compensation%20Guidelines%20V1-2018-05-01.pdf>

⁶ YWB Reasons for Decision HY99-011, September 19, 2002.

⁷ YWB Reasons for Decision HY22-016, March 31, 2023.

1 through ongoing operation of the hydro facility being relicensed at the time to identify
2 themselves and potentially agree to appropriate compensation with Yukon Energy. The
3 process often includes the following steps:

- 4
5 • Yukon Energy providing public notice of the process to address individual claims
6 through print media, posters, social media, and on Yukon Energy's website, as
7 well as through local stakeholder groups.
8
- 9 • Yukon Energy hosting open houses in communities near the hydro facility where
10 individuals who may be adversely affected by the facility's use of water are more
11 likely to reside. The goal of the open houses is to provide information about the
12 claims process and to facilitate claim form filing by applicants.
13
- 14 • Yukon Energy reviewing each claim against the *Waters Act* requirements and the
15 YWB's Compensation Guidelines, and, where needed, following up directly with
16 individual claimants to clarify information presented and issues raised in their
17 claims.
18
- 19 • If and when Yukon Energy determines through this process that an individual
20 appears to have a valid claim for the proposed term of the licence, making an offer
21 to settle their compensation claim, which the claimant can accept or reject.
22
- 23 • Individuals who accept Yukon Energy's compensation proposal are paid the
24 compensation after the issuance of the new water use licence.
25

26 Individuals who reject Yukon Energy's compensation proposal, as well as other individuals
27 who did not participate in Yukon Energy's process or whose claims were denied by Yukon
28 Energy in its process, also have the right to submit their claims for individual compensation
29 directly to the YWB under Part 10 of the YWB's Rules of Procedure.
30

31 Community Compensation:

32 Discussions about community compensation are held between Yukon Energy and
33 representatives from First Nation governments in the relicensing project area during the
34 negotiation of Energy Agreements related to the relicensing project.
35

36 In most cases, Yukon Energy has reached agreements with affected First Nations on
37 community compensation. However, in the case of the most recent Water Use Licence

1 renewal for the Whitehorse Rapids Generating Station (WRGS) in July 2025, no
2 community compensation agreement was reached with the Carcross/Tagish First Nation
3 (C/TFN). In those circumstances, the YWB included a provision in the renewed WRGS
4 Water Use Licence requiring Yukon Energy to provide compensation to C/TFN in the
5 manner and by the date determined by the YWB. If no community compensation
6 agreement is reached with C/TFN by November 28, 2025, it is Yukon Energy's
7 understanding that the YWB may implement a further process to evaluate C/TFN's
8 community compensation claim.

9
10 Other negotiated benefits:

11 Chapter 22 of the Umbrella Final Agreement and Yukon First Nation Final Agreement
12 outlines provisions for Yukon First Nations to be provided with opportunities to maximize
13 specific economic measures (e.g., training, employment, business and contracting
14 opportunities, energy planning) and a First Nation's interest in strategic investments in the
15 areas of renewable resources services and energy resources. Chapter 22 also outlines
16 that project agreements with First Nations may include other measures to mitigate
17 negative socio-economic effects of a project on the First Nation.

18
19 Yukon Energy often initiates discussions with First Nation governments affected by a
20 project about opportunities and interests outlined in Chapter 22 at the start or shortly after
21 a project is initiated. Depending on the type, scope and complexity of the project, as well
22 as the project's known and potential impact on a First Nation's communities and its people,
23 these conversations can involve numerous meetings over several years before Energy
24 Agreement(s) are finalized and signed by Principals. Time is needed to learn about,
25 understand more fulsomely and identify ways to maximize each First Nation's involvement
26 in the project, as well as opportunities to mitigate effects, for ongoing collaboration, and
27 for potential long-term partnerships with each Nation in a way that has meaning for that
28 First Nation and its citizens.

29
30 For complex projects, third-party negotiators are sometimes used to facilitate
31 conversations between Yukon Energy and the First Nations. Legal counsel is also used
32 to draft and review Energy Agreements amongst the Parties.

33
34 **(d)**

35
36 Yukon Energy anticipates that an increase in employee complement could essentially
37 remove costs under the PM Consultant category under the Project Management heading.

- 1 In the future, the plan is for these tasks to be performed by the Permitting and Monitoring
- 2 Coordinator proposed in the Application in 2026 (and now being accelerated as a 2025
- 3 hire – see YUB-YEC-1-38(d)).

1 **REFERENCE:** YEC 2025-2027 Application, MLESP, PDF pages 404, 412-413;
2 Tab 5 tables 2025-27 GRA Supplementary, Tab 5.8 – 2023-2027
3

4 **ISSUE:** Cancelled Mayo Lake Enhanced Storage Project (MLESP)
5

6 **QUOTE:** PDF page 404, footnote 10:

7 “¹⁰ In February 2022, the Yukon Energy Board approved including the
8 activities required to remove the Mayo Lake Control Structure coffer
9 dam remnants in the Mayo water use licence renewal project
10 description and applications for the YESAB, YWB, and DFO processes
11 as part of the broader relicensing for the MGS. Removal of the coffer
12 dam remnants, which was previously part of the MLESP, will provide at
13 least 1.7 GW/year additional renewable energy on average without any
14 MGS water use licence changes to enhance Mayo Lake storage. This
15 approach will allow for consideration of additional options in the future,
16 such as dredging the outlet channel of Mayo Lake and a change in the
17 LSL of Mayo Lake, should they be appropriate.
18

19 PDF page 412:

20 Full costs of the MLESP by year, after transfer of applicable costs to
21 the MGS Relicensing Project, are detailed in the table below. The total
22 rate base impact is \$2.267 million. The other \$2.336 million of costs
23 were transferred to the MGS Relicensing Project.
24

25 PDF page 413:

26 For regulatory purposes, Yukon Energy sees two possible accounting
27 treatments going forward for the remaining MLESP costs of \$2.267
28 million.
29

- 30 1) The MLESP costs could be kept in WIP until the remaining portion
31 of the original project, the removal of the coffer dam, has been
32 completed. The expected completion timing of this is uncertain. The
33 effect of this is the project would continue to accrue AFUDC for
34 several years, based on the time required for completion of the
35 MGS water use licence and then construction for removal of the
36 coffer dam.

1 2) Yukon Energy could transfer the \$2.336 million of costs applicable
2 to the MGS Relicensing Project to that project and close the
3 MLESP. AFUDC on the Mayo Lake Storage project would cease
4 when there was little-to-no probability it would offer a net economic
5 benefit to ratepayers.

6
7 Yukon Energy believes the appropriate accounting treatment is
8 alternative 2 (transfer coffer dam removal costs applicable now to the
9 MGS Relicensing Project and close the MLESP) based on the YUB
10 prior decision on the Southern Lakes Storage Project.

11
12 Yukon Energy had reason to believe that there was a reasonable
13 probability that the MLESP would proceed until February 2022;
14 however, after receiving the letter from FNNND and assessing the
15 options, Yukon Energy no longer had a reasonable basis for assuming
16 that the MLESP components other than the coffer dam removal would
17 likely be able to proceed at this time.”

18
19 **QUESTION:**

20
21 a) Referring to footnote 10 at PDF page 404, how does YEC’s statement that, “in
22 February 2022, the Yukon Energy Board approved including the activities required
23 to remove the Mayo Lake Control Structure coffer dam remnants...” impact YEC’s
24 proposals with respect to MLESP in the current application?

25
26 b) Please explain how YEC has recorded the \$2.267 million in costs related to the
27 “close” of the now cancelled MLESP project; specifically, whether the costs have
28 been reflected in YEC’s revenue requirement as being either capitalized or
29 expensed. Please provide a reference to all schedules within YEC’s application
30 that illustrates the accounting treatment identified.

31
32 c) On what basis did YEC determine that \$2.336 million in coffer dam remnant
33 removal costs should be capitalized to the Mayo Generating Station (MGS)
34 project? In what year were these costs incurred? How do these “removal costs”
35 meet YEC’s criteria for capitalization in the year in which they were incurred?

36
37 d) Referring to Tab 5 tables 2025-27 GRA Supplementary, Tab 5.8 - 2023-2027,
38 please confirm that the offset to the 2024 credit of \$2.3782 million actual capital

1 expenditure shown on row 50 is included in the 2024 debit of \$4.1694 million actual
2 capital expenditure shown on row 53. If not confirmed, please identify where the
3 offset to the \$2.3782 million credit amount is included.

4
5 **ANSWER:**

6
7 **(a)**

8
9 Details of the reason to include the coffer dam removal cost activities as part of the Mayo
10 Generating Station (MGS) Water Use Licence Renewal project are provided in section
11 5.2A-4 of the application on page 407. The significance of this approval meant that the
12 remaining activities in the Mayo Lake Enhanced Storage Project had little-to-no probability
13 of offering a net economic benefit to ratepayers based on current information, and given
14 Board Order 2024-05 directions in paragraph 312 for cancelled projects. The resulting
15 impact is that Yukon Energy ceased AFUDC on the Mayo Lake Enhanced Storage Project
16 at that time, and considered it closed and to be added to rate base. Yukon Energy believes
17 this is consistent with the approach approved by the Board on the cancelled Southern
18 Lakes Storage Enhancement Project in the 2023/24 GRA.

19
20 **(b)**

21
22 Yukon Energy has reflected the \$2.267 million in costs related to the now cancelled
23 MLESP project as capital costs added to rate base. Amortization of the project costs are
24 proposed to occur over ten years at \$0.227 million per year, also consistent with the
25 approach approved by the Board on the canceled Southern Lakes Storage Enhancement
26 Project in the 2023/24 GRA. Schedules within the application that illustrates the
27 capitalization are below.

- 28
29 i. Schedule 3B-2025 Calculation of Amortization Expense for Deferred Costs (2025)
30 ii. Schedule 3B-2026 Calculation of Amortization Expense for Deferred Costs (2026)
31 iii. Schedule 3B-2027 Calculation of Amortization Expense for Deferred Costs (2027)
32 iv. Table 5.3 WIP Continuity Schedule – 2023 Actuals
33 v. Table 5.4 WIP Continuity Schedule – 2024 Preliminary Actuals
34 vi. Table 5.8 WIP Continuity Schedule – 2023-2027 Continuity Schedule

1 **(c)**

2
3 Yukon Energy determined that the \$2.336 million in coffer dam remnant removal costs
4 should be capitalized to the MGS Water Use Licence Renewal project because, through
5 collaboration with FNNND, it was agreed that these activities would be included as part of
6 the MGS licence renewal application.

7
8 As indicated in the business case for the Mayo Lake Enhanced Storage Project in section
9 5.2A-4 of the application starting on PDF page 407, these MLESP costs were incurred as
10 early as 2009 and continued through 2022 when they were transferred to the MGS Licence
11 Renewal project.

12
13 In accordance with Yukon Energy's capitalization policy provided in Appendix 5.3 of the
14 application, the coffer dam remnant removal costs should be capitalized in accordance
15 with section 6.0 Regulatory and Licensing Projects.

16
17 **(d)**

18
19 Confirmed.

REFERENCE: YEC 2025-2027 Application, Table, 5.2-8, Section 5.1B-5:
 Overhauls, PDF pages 199, 353-368

ISSUE: Overhauls

QUOTE: **Overhauls** – The total 2025 through 2027 rate base increase from overhauls approximates \$7.8 million, excluding any depreciation or amortization deductions. Rate base additions relate to the projects in Table 5.2-8:

**Table 5.2-8:
 Overhauls >\$400,000 and <\$2 Million Added to Rate Base**

Project	Forecast Cost (\$M)	In-service
MBH1 Overhaul	\$1.600M	2026
MBH2 Overhaul	\$1.597M	2025
WG1 30,000 Hour Overhaul	\$1.520M	2025
WG3 30,000 Hour Overhaul	\$1.520M	2026
DD4 Overhaul	\$0.975M	2025
WG0 Major Plant Overhaul	\$0.560M	2025

PREAMBLE: In Table 5.2-8 and Section 5.1B-5, YEC has provided details of several overhaul programs for hydro units or various types of engines.

QUESTION:

- a) Please clarify if YEC maintains a schedule of upcoming overhauls that is used for forecasting purposes?
- b) If part (a) is confirmed, please provide YEC's overhaul schedule. Otherwise, please explain how YEC plans for overhauls in terms of forecasting cost, the need for manpower, and estimate of completion time.

ANSWER:

(a) and (b)

Hydro overhauls are planned to occur on a 10-year schedule. This rotation has been shown to be a reasonable period for major renewal, based on the found condition of wear components exposed during the overhauls themselves. Those components addressed

1 during the overhaul require more time and more extensive disassembly to renew than the
2 annual maintenance window will allow.

3
4 The Hydro overhauls are managed by engineering and project management. Engineering
5 will plan and scope an overhaul a year in advance of actual overhaul work to:

- 6
7 • Inspect the unit to establish a scope of work and schedule baseline, within the
8 limits of what can be determined without full disassembly;
9
- 10 • Determine contractor, work management, project management and QA/QC
11 (quality assurance/quality control) strategy;
12
- 13 • Procure long lead parts which are known to be needed based on experience and
14 inspection;
15
- 16 • Go to market for a technical contractor to perform the work; and
17
- 18 • Improve the budget estimate for the year ahead.
19

20 Units planned for work within the next 5 years are budgeted for in Yukon Energy's 5-year
21 capital plan and are shown as budget estimates in the plan. Future work is roughly
22 budgeted at order of magnitude until the scope of work is developed closer to the time of
23 work, and contractor cost estimates are in hand. After the scoping and planning exercise
24 performed by Engineering, the cost estimate to perform the overhaul can be improved to
25 be included in the business plan for the year ahead. It should be noted that there is always
26 some volatility in these turbine and generator overhauls since a complete understanding
27 of the work required to be done cannot be known until the unit itself is disassembled.
28 Contractor costs have also been rising unpredictably in the past few years, further
29 cementing the need to scope and plan the work in advance.
30

31 The forward-looking plan for Major Hydro Overhauls is copied below. This schedule
32 follows the 10-year rotation plan. Due to WH3 being overdue for an overhaul as described
33 in section 5.1A-12 on PDF page 298 of the application, the schedule has been amended
34 by moving the WH3 overhaul to 2027 and the WH4 overhaul (last performed in 2017) to
35 2028.

1

2

3

4

5

1 **REFERENCE:** YEC 2025-2027 Application, PDF page 480

2
3 **ISSUE:** LWRF Account

4
5 **QUOTE:** YEC is directed to populate and provide the following table for each
6 year since 1989 regarding the LWRF balance as part of its compliance
7 filing to this Board Order and to continue to provide updates to this table
8 as part of it future general rate applications.
9

10 **PREAMBLE:** The above quote comes from Appendix A to Board Order 2024-05 (PDF
11 page89, paragraph 386). In this application YEC stated “The table, as
12 directed by the Board, is provided as part of the annual LWRF filings
13 with the Board.”
14

15 **QUESTION:**

- 16
17 a) The Board directed that the aforementioned table is to be updated and be part of
18 future general rate applications. Please provide the table as directed.
19

20 **ANSWER:**

21
22 **(a)**

23
24 Please see YUB-YEC-1-86 Attachment 1 for a copy of the LWRF continuity schedule filed
25 in the LWRF 2024 annual filing.

Yukon Energy 2025-27 GRA
YUB-YEC-1-86 Attachment 1

Low Water Reserve Fund (LWRF) Continuity Schedule (\$000)

Year (Note 1)	Opening Balance (Note 2)	Water Availability (LTA) Adjustment (+/-) (Note 3)	Finance Charge (+/-) (Note 4)	Adjustment for balances outside fund caps (Note 5)	Other Adjustments (Note 6)	Ending Balance	Active (A)/Inactive '(I) (Note 7)
1989	2,000					2,000	I
1990	2,000					2,000	I
1991	2,000	10				2,010	A
1992	2,010	290				2,300	A
1993	2,300				-400	1,900	I
1994	1,900				-1400	500	I
1995	500					500	I
1996	500	-1,458	189		3,540	2,771	A
1997	2,771	-191	85		170	2,835	A
1998	2,835	467	159		-1,225	2,236	A
1999	2,236	-1,132	43		-499	648	A
2000	648		35			683	I
2001	683		33			715	I
2002	715		19			734	I
2003	734		21			755	I
2004	755		16			772	I
2005	772		19			791	I
2006	791		30			821	I
2007	821		35			856	I
2008	856		27			883	I
2009	883		4			887	I
2010	887		4			891	I
2011	891		11			902	I
2012	902	3,715	11			4,628	A
2013	4,628	3,518	52			8,198	A
2014	8,198	1,342	87			9,627	A
2015	9,627	1,974	53	-759		10,895	A
2016	10,895	990	54	-2,454		9,485	A
2017	9,485	0	86	-2,861		6,710	A
2018	6,710	-534	76	-2,874		3,379	A
2019	3,379	-6,268	-7	-1,004		-3,900	A
2020	-3,900	-352	-20	0		-4,272	A
2021	-4,272	7,019	-3	0		2,744	A
2022	2,744	7,151				9,895	A
2023	9,895	5,791	629			16,314	A
2024	16,314	-3,067	1,012	-74		14,186	A
2025	14,186						

Notes:

1. Year refers to the YEC calendar year, ending December 31.

2. Balance at start of fiscal year in YEC fund to address YEC thermal generation cost changes from forecast due to changes in water availability. This fund's name and terms have varied over the years, e.g., low water fund, Diesel Contingency Fund (DCF), Low Water Reserve Fund (LWRF). YEC's first GRA filing for the 1989/90 GRA indicated that a reserve of \$2 million had been established by YEC out of retained earnings in 1987 to assist in maintaining rate stability in the event of increased costs to produce electricity by diesel generation at times of low water conditions and shut downs of hydro facilities. Subsequent changes to the fund are due to factors as explained in the table based on the approach approved for the calculations in place at the time. A positive balance means owing to customers while a negative balance owing to YEC.

Yukon Energy 2025-27 GRA
YUB-YEC-1-86 Attachment 1

3. Water Availability Adjustment refers to the annual adjustment to the LWRF due to the difference between forecast renewable generation and actual renewable generation based on the approach approved for the calculations in place at the time. Long-term average (LTA) forecasts for water availability were first approved for setting rates in the 1996/97 GRA (Order 1996-7). Where relevant, adjustments address wind or other non-hydro variances in renewable energy availability.
4. Finance charge refers to the change in the LWRF due to interest or equivalent calculations.
5. When the fund is outside its caps (currently set at +/- \$16 million), YEC must request a rider to either charge or refund to customers amounts to bring the balance of the LWRF within the boundaries of the fund caps. The current Rider E is a refund of 0.128 cents/kWh.
6. Other adjustments reflect the following:
 - a. In response to closure of the Faro mine and its impact on YEC rates and reserve requirements for potential low water conditions, Board Order 1993-8, section 5.1.4.3 approved a \$0.4 million allocation to 1993 and a \$1.4 million allocation to 1994 as an offset to the 1993 and 1994 revenue requirements.
 - b. The adjustment for 1996 reflects the Settlement approved in Order 1996-7 to replenish the DCF using funds from pre-1996 reserves related to the Faro mine bad debt payment and net recoveries related to reopening of the Faro mine.
 - c. The adjustments for 1997, 1998 and 1999 reflect credits applied as per Board Order 1997-7 related to Faro mine closure as well as adjustments related to Whitehorse Hydro Plant Fire and Forest Fires [RFID related transactions].
7. Indicate whether the LWRF was active or inactive for that given year. Inactive periods occurred when mine closures reduced hydro grid loads to levels where water availability was not expected to materially affect thermal generation costs. The table reflects years when actual renewable availability ended up impacting the LWRF/DCF (even if actual YUB decisions related to such changes to the fund were deferred until subsequent years).

1 **REFERENCE:** YEC 2025-2027 Application, PDF pages 481-482 and Footnote 1.

2
3 **ISSUE:** LWRF and Fish Lake Hydro

4
5 **QUOTE:** PDF page 481-482:

6 Prior to OIC 2021/16, as noted in the above reference to Board Order
7 2014/16, Yukon Energy GRAs have sought to apply LTA hydro
8 generation for Fish Lake hydro when determining the wholesale firm
9 purchases by AEY, applying the same LTA principles as Yukon Energy
10 used to forecast its own hydro and thermal generation for GRA
11 purposes. The Board approved this use of LTA for Fish Lake hydro
12 generation when Yukon Energy GRA's provided for the use of LTA Fish
13 Lake hydro in its filing.

14
15 Yukon Energy understands that OIC 2021/16 now requires the use of
16 LTA for any renewable generation forecasts in a Yukon Energy GRA,
17 and that this requirement includes the use of LTA for Fish Lake hydro
18 forecasts used to forecast Yukon Energy wholesale sales requirements
19 that directly impact the forecast of Yukon Energy forecast generation
20 and related forecast thermal generation for test year revenue
21 requirements.

22
23 Footnote 1:

24 The OIC 2021/16 amendment to OIC 1995/90, in Section 9.1,
25 subsection 3, directs that when the Board is determining forecast fuel
26 costs for the forecast thermal generation needed to meet forecast
27 customer requirements (per subsection 2) "...the Board must determine
28 the forecast fuel costs for a financial year of Yukon Energy Corporation
29 by (a) forecasting the amount of renewable generation available to
30 contribute to meeting forecast customer requirements, based on long-
31 term average annual renewable source availability; (b) forecasting the
32 amount of thermal generation needed to meet any shortfall between
33 the forecast renewable generation under paragraph (a) and forecast
34 customer requirements."

1 **QUESTION:**

2
3 a) Does AEY generation first serve AEY load?

4
5 b) If part (a) is affirmative, then, in principle, are AEY wholesales determined by AEY
6 total load less AEY generation less IPP connected to AEY system less
7 microgeneration connected to the AEY system? Please explain.

8
9 c) If the above parts are true, then should Fish Lake be treated as a net to AEY
10 wholesale sales?

11
12 d) If part (c) is true, then, as OIC 2021/16 is only applicable to YEC, shouldn't the
13 forecast for Fish Lake be based on the expected generation for the test period (not
14 LTA)? Please explain.

15
16 e) Similarly, should any generation not owned by YEC that is directly connected to
17 the AEY system be treated as an offset to wholesale sales? Please explain.

18
19 **ANSWER:**

20
21 **(a) to (c), (e)**

22
23 Confirmed.

24
25 AEY's firm power purchases from Yukon Energy are the result of the total AEY grid load,
26 less AEY Fish Lake generation, less AEY grid standby diesel generation, and less micro-
27 generation. AEY does not have Electricity Purchase Agreements with IPPs connected to
28 the YIS.

29
30 **(d)**

31
32 OIC 2021/16 is an amendment to *Rate Policy Directive (1995)* (OIC 1995/090), which
33 applies generally to the YUB's setting of electricity rates in Yukon for both Yukon Energy
34 and AEY. It includes provisions adding sections 10 and 11 to the *Rate Policy Directive*,
35 which apply to the rates of both public utilities, Yukon Energy and AEY.

1 With respect to section 9 of the *Rate Policy Directive* (as amended by OIC 2021/16),
2 subsection 9(2) imposes a specific direction on the Board requiring it to include provision
3 in Yukon Energy's rates to allow Yukon Energy to recover forecast fuel costs in
4 accordance with the methodology set out in subsection 9(3). For that purpose, however,
5 the reference in paragraph 9(3)(a) to the forecast "amount of renewable generation
6 available to contribute to meeting forecast customer requirements, based on long-term
7 average annual renewable source availability" includes "renewable generation" from all
8 renewable sources, as defined in section 1, regardless of the ownership of those sources.
9 In particular, it includes hydro generation from Fish Lake (owned and operated by AEY)
10 that is forecast to be available to reduce Yukon Energy customer requirements – including
11 wholesales to AEY – despite the fact that section 9 does not speak to AEY's rates.

12
13 Accordingly, for the purposes of the YEC GRA, paragraph 9(3)(a) of the *Rate Policy*
14 *Directive* requires that the forecast for Fish Lake must be based on LTA generation and
15 not expected generation for the test period.

16
17 The power purchase forecasts provided by AEY for this GRA are already net of Fish Lake
18 generation, therefore, for purposes of calculating the revenue requirements for the 2025-
19 2027 test years, Yukon Energy has continued to assume wholesale forecasts as provided
20 by AEY net of Fish Lake LTA. Yukon Energy has not, however, received from AEY any
21 confirmation that the Fish Lake Hydro sales assumed for their wholesale forecasts are
22 based on LTA.

23
24 Please see response to YUB-YEC-1-34 a) and b) for additional information.

1 **REFERENCE:** YEC 2025-2027 Application, Tab 7 Schedules 2 and 2A, PDF pages
2 493-494.

3
4 **ISSUE:** Working Capital

5
6 **PREAMBLE:** The Board requests more information on the derivation of working
7 capital.

8 **QUESTION:**
9

10 a) Line 4 of Schedule 2 is described as 27/365. Please describe what this represents,
11 when it was first used and what review has been undertaken since this number
12 was implemented.

13
14 b) Line 4 of Schedule 2 is described as inventory (three-year average). Where
15 are the inventory numbers derived from? What is the composition of YEC's
16 inventory? For an annual calculation of working capital, why is a three-year
17 average used?

18
19 c) For Schedules 2 and 2A please provide the final 2024 actual numbers.

20
21 d) For Schedule 2A, please provide a variance explanation for line 1 (expenses
22 subject to GST) comparing 2024 final actuals to 2024 GRA compliance.

23
24 e) For Schedule 2A, please explain the derivation of the amounts "expenses subject
25 to GST".

26
27 f) For lines 4 and 9 (day factor, please explain how these numbers were derived
28 and the process used to check the continued validity of those numbers.

29
30 g) Has YEC ever undertaken a lead-lag study for working capital calculations? Please
31 explain.

32
33 **ANSWER:**

34
35 **(a), (f) and (g)**

36
37 The number 27 in line 5 of Schedule 2 in Tab 7 represents the net lag days based on the
38 lead/lag study [average lag in revenue collections of 33, less average lag in payment of

1 operating expenses of 6]. It was first used in Yukon Energy's 2005 Required Revenues
2 and Related Matters application and has since been used in the calculation of the
3 allowance for working capital.

4
5 No reviews or studies have been undertaken since. Yukon Energy has sought to maintain
6 a simple and streamlined approach to help keep regulatory costs down. There would not
7 be a material change in revenue requirements from completing another full review of
8 lead/lag days.

9
10 Similarly, the day factors in Schedule 2A lines 4 and 9, represent lag days in revenue
11 collections and GST payments. There have not been any changes as to how the revenues
12 are collected or GST payments are made. Therefore, the day factors remain reasonable.

13
14 **(b)**

15
16 Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. The
17 inventory numbers for the actual years are from the financial statements, while for the
18 forecast years, they also include the forecast inventory balances. For example, the
19 inventory balance of \$5.079 million used for working capital allowance for 2024 represents
20 the average of actual inventory balances for 2022 [\$4.944 million], 2023 [\$5.072 million]
21 and 2024 [\$5.221 million]. Using a three-year average is an industry standard and is used
22 by many utilities. Yukon Energy has been using this approach since the 1990s [for
23 example, the Board in its Order 1992-1, Schedule B calculates the working capital
24 requirements using the three-year average inventory balances.

25
26 **(c)**

27
28 Please see YUB-YEC-1-88 Attachment 1.

29
30 **(d) and (e)**

31
32 The expenses subject to GST in Schedule 2A include O&M expenses, including fuel, but
33 excluding donations, net increase in capital, including deferred costs. The variance of
34 about \$48 million between the 2024 approved and the 2024 preliminary actual
35 predominantly reflects lower-than-forecast increase in capital. For example, as reviewed
36 in Schedule 1 in Tab 7, the year-end balance of Property, Plant and Equipment in 2024
37 [\$843 million] was about \$48 million lower than the 2024 GRA [\$891 million].

Yukon Energy Corporation
Computation of Allowance for Working Capital
(\$000s)

Schedule 2
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Operating and maintenance	S.5 L.5	54,096	48,623	56,547	61,667	66,076	69,135
2	Taxes other than income	S.5 L.6	777	756	759	771	790	806
3	Non-allowable expenses	S.5 L.12	(120)	(121)	(114)	(120)	(120)	(122)
4	Cash operating expenses		54,752	49,258	57,192	62,317	66,746	69,818
5	27/365		4,050	3,644	4,231	4,610	4,937	5,165
6	Inventory (three year average)		4,817	4,790	5,079	5,171	5,221	5,221
7	GST Impact on working capital	S.2A L.11	(170)	(191)	(274)	(209)	(278)	(334)
8	Working capital	S.1 L.14	8,697	8,242	9,035	9,572	9,880	10,052

Yukon Energy Corporation
Effect of GST on Working Capital
(\$000s)

Schedule 2A
2025-27 GRA

Line No.	Description	Cross Ref.	2024 GRA Compliance	Actual 2023	Actual 2024	Forecast 2025	Forecast 2026	Forecast 2027
1	Expenses subject to GST		139,615	97,303	85,802	159,554	161,358	163,401
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		6,981	4,865	4,290	7,978	8,068	8,170
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		268	187	165	306	309	313
6	Revenue subject to GST		91,344	78,934	91,523	107,392	122,406	134,850
7	GST blended rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		4,567	3,947	4,576	5,370	6,120	6,742
9	Day factor		35	35	35	35	35	35
10	Payable portion of GST impact		438	378	439	515	587	647
11	Net impact of GST on working capital	S.2 L.7	(170)	(191)	(274)	(209)	(278)	(334)