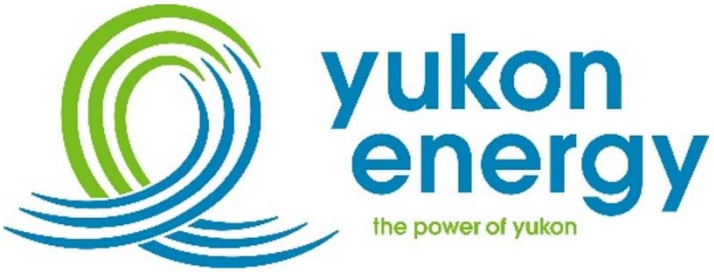


YUKON ENERGY CORPORATION

2023/24 GENERAL RATE APPLICATION
ROUND 1 INTERROGATORY RESPONSES FILED

November 29, 2023

John Maissan
(JM)

TOPIC: **General and Introduction to the Application**

REFERENCE: Board Order 2023-23 and BCUC Generic Cost of Capital decision:

QUESTION:

a) What would be the changes in residential power bills from the present through 2024 by date (and beyond if applicable) if YEC's application is approved as submitted?

b) Please recalculate the response to (a) above if the BCUC GCOC decision increasing the ROE for a low risk utility by 0.90% from the previous 8.75% to the present 9.65% is applied to YEC's proposed ROE.

ANSWER:

(a)

In its 2023/24 GRA, Yukon Energy applied for an interim Rider J change of 4.80% effective October 1, 2023, followed by a 12.02% increase effective January 1, 2024, and final rates effective August 1, 2024. The bill impacts for these interim Rider J changes are provided in Table 4.3 of Tab 4 of the Application.

The Yukon Utilities Board (YUB or Board) Order 2023-23, however, approved an interim refundable Rider J increase of 10% effective January 1, 2024 [no increase prior to January 1, 2024]. This increases Rider J for non-industrial retail customers from 34.84% to 44.84%. The following table recalculates the residential bill with 1,000 kWh/month consumption based on interim Rider J as approved in YUB Order 2023-23 and assuming YEC's 2023/24 GRA application with a total of 14.11% rate increase is approved. The bill calculations assume the Rider F rate is reduced effective January 1, 2024, and for consistency purposes, the bill calculations exclude AEY's 2023-24 GRA interim Rider R increase approved effective January 1, 2024 and AEY Rider S. The bill calculations with AEY's 2023/24 GRA interim increase and Rider S are provided in response to UCG-YEC-1-6 (c).

Table 1: Estimated Bill Impacts for Residential & Commercial Non-Government Customers with 14.11% rate increase

	Pre-2023/24 GRA	YEC 2023/24 GRA [excludes AEY GRA]	
	July 2023	January 1, 2024 Interim [YUB 2023-23], assumes Rider F rate $0/kWh	August 1, 2024 Final/True-up
	A	B	C
Monthly Bills			
Residential Non-Government, Whitehorse [$/month]			
1,000 kWh/month consumption	**$215.2**	**$212.4**	**$231.9**
change from July 2023, $/month		*-$2.7*	*$16.7*
change from July 2023, %		-1.3%	7.8%
Incremental change, %		-1.3%	9.2%
Commercial Non-Government, Whitehorse [$/month]			
2,000 kWh/month consumption [5 kW demand]	**$379.0**	**$370.0**	**$403.9**
change from July 2023, $/month		*-$9.0*	*$24.9*
change from July 2023, %		-2.4%	6.6%
Incremental change, %		-2.4%	9.2%

(b)

YEC's ROE as filed in the GRA of 8.70% was based on the previous BCUC benchmark, with a 45-basis point risk premium and a 50-basis point reduction required per OIC 1995/90.

Simply adjusting YEC's filed ROE by 90 basis points, as requested in this IR, to reflect the BCUC GCOC decision ROE increase for a low risk utility would increase YEC's test year ROE from 8.70% to 9.60%, increasing the revenue requirements and revenue shortfalls by about $1.2 million for 2023 and by $1.4 million for 2024 and resulting in an overall rate increase of 15.36% compared to 14.11% as filed. Table 2 illustrates as requested the estimated bill impacts with 15.36% overall rate increase.

Table 2: Estimated Bill Impacts for Residential & Commercial Non-Government Customers with 15.36% rate increase

	Pre-2023/24 GRA	YEC 2023/24 GRA [excludes AEY GRA]	
	July 2023	January 1, 2024 Interim [YUB 2023-23], assumes Rider F rate $0/kWh	August 1, 2024 Final/True-up
	A	B	C
Monthly Bills			
Residential Non-Government, Whitehorse [$/month]			
1,000 kWh/month consumption	**$215.2**	**$212.4**	**$236.2**
change from July 2023, $/month		*-$2.7*	*$21.0*
change from July 2023, %		-1.3%	9.8%
Incremental change, %		-1.3%	11.2%
Commercial Non-Government, Whitehorse [$/month]			
2,000 kWh/month consumption [5 kW demand]	**$379.0**	**$370.0**	**$411.3**
change from July 2023, $/month		*-$9.0*	*$32.3*
change from July 2023, %		-2.4%	8.5%
Incremental change, %		-2.4%	11.2%

Please see YUB-YEC-1-85 (a and b) for details regarding the recent BCUC GCOC Stage 1 decision and implications for ROE determinations for current AEY and YEC GRA proceedings.

TOPIC: **General and Introduction to the Application**

REFERENCE: Page 7 adjusted fuel prices**:**

QUESTION:

a) Please provide a table of the actual delivered fuel prices per litre for LNG and diesel (weighted by delivery volume for each location) for each month beginning in January 2021 through to the most recent complete month for which data is available.

b) How does Yukon Energy forecast LNG and diesel fuel supply costs will vary over the next two years?

ANSWER:

(a)

Please see the tables below that show the weighted average monthly delivered LNG and diesel fuel prices for January 2021 through September 2023.

Table 1: Weighted Average LNG Delivered Price, $/litre

	2021	2022	2023
January	$0.51	$0.56	$0.48
February	$0.55	$0.55	$0.49
March	$0.43	$0.62	$0.52
April	$0.52	$0.61	$0.50
May	$0.52	$0.64	$0.41
June	$0.51	n/a	$0.50
July	n/a	$0.59	$0.50
August	$0.54	$0.50	$0.45
September	$0.53	$0.61	$0.51
October	$0.58	$0.54	
November	$0.56	$0.59	
December	$0.54	$0.56	

Table 2: Weighted Average Diesel Delivered Price, $/litre

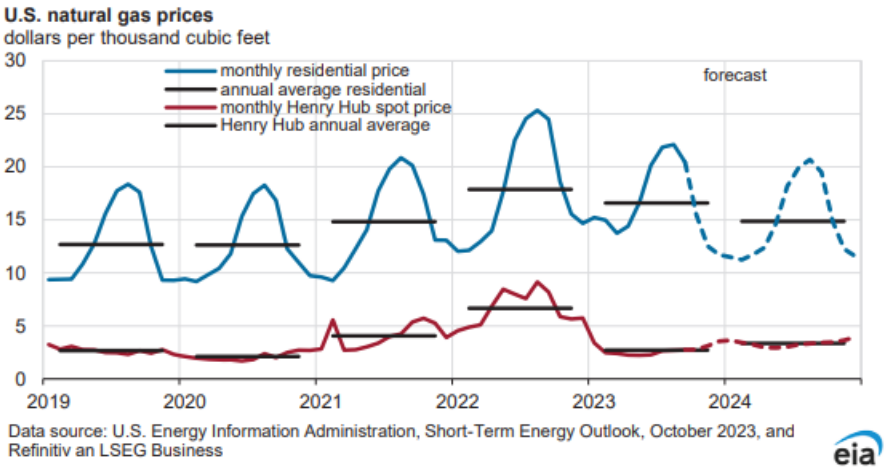
	2021	2022	2023
January	$0.84	$1.11	$1.50
February	$0.87	$1.23	$1.37
March	$0.96	n/a	$1.26
April	$0.94	$1.51	$1.18
May	$0.90	$1.74	$1.23
June	$1.08	$1.61	$1.19
July	$1.07	$1.71	$1.19
August	$1.11	$1.45	$1.31
September	$1.08	$1.67	$1.43
October	$1.10	$1.48	
November	$1.09	$1.63	
December	$0.97	$1.59	

(b)

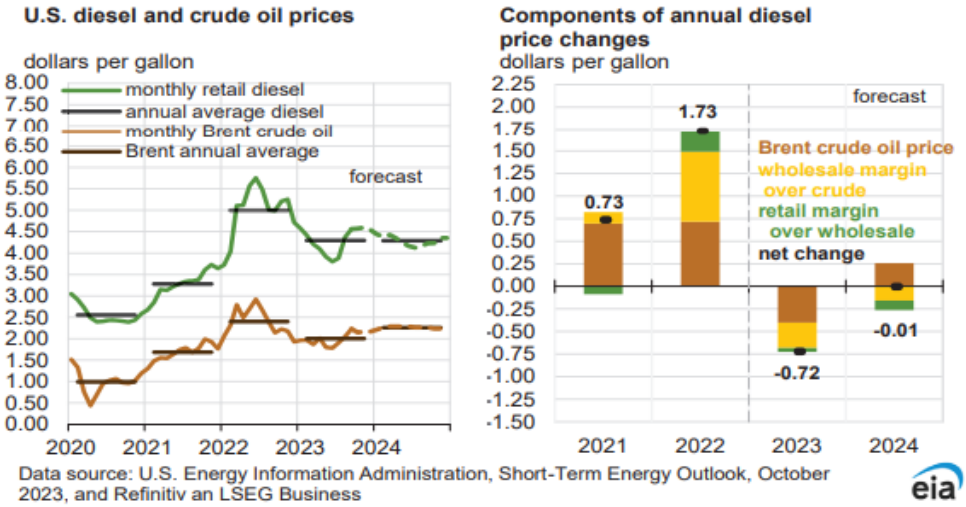
YEC's delivered LNG prices include commodity costs, as well as liquefaction and transportation costs. Liquefaction and transportation costs are determined based on a contract signed with Ferus and impacted by the inflation rates, while the commodity prices are tied to the market prices.

The market prices for natural gas and diesel could vary depending on changes in supply and demand and other factors. The following figures show forecast fuel prices available from the US Energy Information Administration (EIA) October 2023 Short-term Energy Outlook.

The EIA's short-term energy outlook shows Henry Hub spot natural gas prices in 2024 are expected to be relatively close to the 2023 prices and much lower than the 2022 actual prices.



Similarly, the EIA's short-term energy outlook also shows diesel and crude oil prices in 2024 are expected to be relatively close to the 2023 prices and much lower than the 2022 actual prices.



TOPIC: **Tab 1 Introduction**

REFERENCE: Page 1-5 (PDF 20/597) Diesel rental costs

QUESTION:

a) What is the average capital cost expended or expected to be expended on YEC infrastructure to be able to grid connect each additional rental diesel unit not previously required?

b) What is Yukon Energy's cost in materials and labour to install and connect and then disconnect and un-install each rental diesel unit each year?

c) What is the rental cost per diesel unit per month ore per season?

d) For how many months each season are the diesel units rented? If not the same for all units, please provide a breakdown of the numbers.

e) What is the energy projected to be required from rental diesels for maintenance purposes only?

f) What is the energy projected to be required from rental diesels to meet the load forecast? Does this include any energy required for maintenance as included in the answer to (d) above?

ANSWER:

(a)

The $4.3 million capital cost of the 2023 Mayo-Faro Diesel Infrastructure identified at page 1-5 is reviewed on page 5.1A-13 of the Application.

The new Mayo diesel infrastructure development cost is $3.44 million and includes preliminary engineering, planning, design, materials, construction, and commissioning. The new Mayo site is expected in 2023 to host 5 diesel rental units [or about $0.7 million/unit] not previously required. This new Mayo infrastructure has the potential to be

used to connect additional permanent diesel units in the future, either replacement of units within the Mayo townsite or new thermal capacity.

The $0.86 million balance of Diesel Infrastructure capital cost is for significant modifications in 2023 at the Faro diesel plant to accommodate construction activities for the Thermal Replacement Project, including moving rental units away from the new thermal plant site and purchasing new switchgear to install the currently planned diesel rental units in the new locations.

(b)

The contractor connection and disconnection costs are included in the rental cost. There are no significant YEC materials costs involved in connection and disconnection. Please see the response to YUB-YEC-1-24 (d) and (e).

(c) and (d)

The diesel units are rented per winter season, from December to mid-April [about 140 days based on five 28-day cycles].

Please see the response to YUB-YEC-1-1 (a) - (c).

(e) and (f)

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

TOPIC: **Tab 1 Introduction**

REFERENCE: Page 1-5 (PDF 20/597) Rate base additions:

QUESTION:

a) What is the capacity (continuous) of the Faro diesels being added to the grid?

b) If the $12.8 million includes infrastructure beyond the diesel generators themselves, please provide a breakdown of these costs.

ANSWER:

(a) and (b)

The total added capacity for the Faro diesel replacement project is 5 MW, two 2.5 MW EPA Tier 4 modular diesel units, expected to be available for the 2024/25 winter to displace diesel rentals.

The total forecast cost of $18.2 million for Faro diesel replacement capital costs shown at page 1-5 includes $15.2 million EPC contractor cost and about $3 million other costs as detailed in Table 5.1A-1.1 in Tab 5.

Item Description	Amount
EPC Contractor – Faro	15,180,000
Faro share of Thermal Replacement Project non-EPC Contractor costs for Faro, Whitehorse and Dawson estimated at approximately 30.3% of $9.885 million (includes Station Service Supply ($0.45 million), YEC internal cost ($1.185 million), Owner's Engineer (BBA at $0.655 million), Assessment and Permitting ($0.29 million), Engagement ($0.28 million), Fuel for on-site commissioning ($0.89 million), Contingency ($2.379 million), AFUDC ($1.71 million), feasibility and engineering ($0.162 million), initial planning costs ($1.884 million).	2,995,000
Total Budget	**18,175,000**

TOPIC: **Tab 3 Revenue Requirement**

REFERENCE: Page 3-17 (PDF 65) "Additional dependable capacity is forecast to be commissioned during 2024 … however, pending confirmation before approximately June 2024 of ability to rely on any such new facilities during all of winter 2024/25, YEC must retain diesel rentals as currently planned."

QUESTION:

a) Please provide an update on when Yukon Energy now expects the BESS project to be fully installed?

b) How long is it anticipated that the commissioning process for "programming" the BESS to provide dependable capacity will take?

c) How long is the commissioning for the "programming" of the other ancillary services that the BESS is planned to provide (as per the BESS regulatory proceeding) anticipated to take?

ANSWER:

(a)

Please see the response to YUB-YEC-1-44.

(b) and (c)

Yukon Energy expects that at least one winter season of testing is required to fully understand the BESS capabilities to provide dependable capacity and other ancillary services such as spinning/operating reserve.

TOPIC: **Tab 5 Capital Projects**

REFERENCE: DSM programming

QUESTION:

a) When does Yukon Energy anticipate that the proposed programming will be available to retail residential customers?

b) When does Yukon Energy anticipate that the proposed programming will be available to retail commercial customers?

ANSWER:

(a) and (b)

The DSM programming will be available to eligible retail residential customers in November 2023. Yukon Energy is tentatively planning to expand its programming to include retail commercial customers by 2026.

REFERENCE: Tab 5 Capital Projects

QUESTION:

a) Please provide status updates on the following capital projects:

   a) The Atlin hydro project
   b) Southern Lakes Enhanced Storage project
   c) Mayo Enhanced Storage project
   d) Tutshi - Moon Pumped Hydro Storage project

ANSWER:

(a)

The conditions precedent have been extended to June 30, 2024. Please see response to YUB-YEC-1-45.

This project requires permits and significant government funding to proceed. The project was referenced in the 2023 Federal Budget, however, no clear funding mechanisms were provided. Yukon Energy alongside Yukon Development Corporation, and the Tlingit Homeland Energy Limited Partnership (THELP) continue to have discussion with federal officials to explore funding avenues to support the project.

(b)

Please see Appendix 5.2A, section 5.2 A-3 of the Application. In November 2022, the Carcross/Tagish First Nation (CTFN) notified YEC that it would not support the completion of the Southern Lakes Enhanced Storage project. As a result, YEC decided not to proceed with the project.

(c)

YEC does not have the support of the First Nation of Na-Cho Nyak Dun (FNNND) to proceed with the full scope of the Mayo Lake Enhanced Storage project (MLESP) at this time. One component of MLESP, removal of remnants of the old coffer dam at the outlet

of Mayo Lake, is being considered as part of current discussions YEC is having with FNNND as part of the Mayo Generating Station Relicensing Project.

(d)

At this time, YEC does not have the support needed from First Nation communities to work on this project.

Nathaniel YEE
(NY)

REFERENCE: **Application, PDF p.2**

QUOTE: Yukon Energy Corporation's (Yukon Energy or YEC) 2023/24 General Rate Application (the GRA or Application) addresses changes to Yukon Energy's approved revenue requirement and other matters through implementation of an adjusted Rider J in order to meet Yukon's need for an increasing supply of safe, reliable and sustainable electricity. (GRA first paragraph, PDF p.2)

QUESTION:

How much of this GRA actually supports increasing the supply of sustainable electricity?

Please provide three lists of capital projects categorized as follows:

a) A list of capital projects supported by this GRA which provide new sustainable / renewable capacity. (Atlin, Moon Lake, etc. if these are supported in this GRA?)

b) A list of capital projects supported by this GRA which provide thermal capacity. (such as diesel replacement and upgrades, Mayo diesel, etc.)

c) A list of capital projects in this GRA which support both new sustainable and thermal projects. (example: Whitehorse Interconnection which supports BESS and rental diesel)

   Each item on each of the lists should have dollar amount provided by this GRA, and a) and b) should also list MW capacity as appropriate. Please also provide a total for each category.

d) Is it fair to claim this GRA is about "safe, reliable and sustainable electricity" given that much of the GRA is about diesel replacement (not sustainable) and rental diesel (not reliable or sustainable)?

ANSWER:

(a) to (c)

It is important to note that the Yukon grid is one interconnected system, so essentially most costs contribute either directly or indirectly to safe, reliable and sustainable electricity. This includes some of the less significant capital or operations maintenance to maintain the system. For example, computer replacement or vehicle purchases are required to support the system, but it is not possible to determine how much capacity they contribute individually. It is also difficult to determine the capacity provided for some of the more significant projects. For example, the Mayo-Faro Diesel Infrastructure does not directly provide a certain amount of capacity. It provides an infrastructure that will support a variable amount of capacity while used for diesel rentals, and could change in the future if permanent diesels are installed there. Another example is Transmission projects. Without these projects, specific generation spending would not be effective.

A summary of the more significant sustaining capital projects is provided on page 5-4 of the Application, which also shows the net rate base impact of approximately $30.262 million. A summary of the more significant capital investments on new supply options to maximize renewable energy generation is provided on page 5.5 of the Application, which also shows the net rate base impact of approximately $7.867 million.

A summary of the more significant spending to address capacity planning requirements is provided on page 5-3 of the Application, which shows the net rate base impact of approximately $33.825 million. This includes the Whitehorse Interconnection project of $11.199 million that supports both new sustainable and renewable projects.

Additional details of these more significant projects are included in the business cases in Appendix 5.1A.

(d)

The diesel generators are a key part of the system that allows us to optimize hydro and other renewable sources of energy. If we continue to think in terms of parts of a system and their temporary impacts, then we will erode our abilities to maintain as high a percentage of renewable energy.

The diesel generators are an absolute necessity for the system to function today, and today's system has 90% renewable energy capability. From January to April of 2023, the rental diesel generators in Whitehorse and Faro generated approximately 2.7 GW.h of electricity, less than 2% of electricity Yukoners used during this period.

It is not all about financial factors. With an isolated grid, YEC needs to make cautious decisions around securing the needed generation from year to year.

QUESTION:

a) Please provide an updated and complete YIS Generation Inventory that includes the rentals (and spares) for 2023-24. Format should be the same as "Appendix A: Existing Resources Technical Attributes" on p. 71 of the 10-Year Renewable Electricity Plan from 2020.

ANSWER:

(a)

Please see NY-YEC-1-2 Attachment 1 prepared based on 2023/24 GRA assumptions, including new diesel replacements and diesel rentals.

YEC 2023/24 GRA
NY-YEC-1-2 Attachment 1

Dependable Capacity based on YEC's 2023/24 GRA Assumptions

Location	Retirement Year	Original Unit #	Prime Mover Type	Dispatchable	Name Plate Capacity (kW)	2023/24 F Dependable Capacity (kW)	2024/25 F Dependable Capacity (kW)
Aishihik							
Hydro	2050	AH1	hydro	Yes	15,600	15,000	15,000
	2050	AH2	hydro	Yes	15,600	15,000	15,000
	2050	AH3	hydro	Yes	7,000	7,000	7,000
					38,200	**37,000**	**37,000**
Faro							
Diesel	2050	FD7	diesel	Yes	3,000	3,000	3,000
	2064	New Diesel	diesel	Yes	5,000		5,000
					8,000	**3,000**	**8,000**
Dawson							
Diesel	2050	DD1	diesel	Yes	800	850	850
	2050	DD2	diesel	Yes	1,000	1,000	0
	2050	DD3	diesel	Yes	1,000	1,030	1,030
	2050	DD4	diesel	Yes	1,440	1,440	1,440
	2050	DD5	diesel	Yes	1,500	1,500	0
	2050	YM1	diesel	Yes	1,440	1,200	1,200
					7,180	**7,020**	**4,520**
Mayo							
Diesel	2050	MD1	diesel	Yes	1,000	1,000	1,000
	2050	MD2	diesel	Yes	1,000	1,000	1,000
	2050	MD3	diesel	Yes	1,000	950	950
					3,000	**2,950**	**2,950**
Hydro	2050	MH1	hydro	Yes	2,550	1,500	1,500
	2050	MH2	hydro	Yes	2,550		
	2050	MBH1	hydro	Yes	5,310	2,500	2,500
	2050	MBH2	hydro	Yes	5,310	2,500	2,500
					15,720	**6,500**	**6,500**
Whitehorse							
Hydro	2050	WH1	hydro	Yes	5,800	3,500	3,500
	2050	WH2	hydro	Yes	5,800	4,138	4,138
	2050	WH3	hydro	Yes	8,400		
	2050	WH4	hydro	Yes	21,327	20,000	20,000
					41,327	**27,638**	**27,638**
Natural Gas	2055	WG1	Natural Gas	Yes	4,400	4,200	4,200
	2055	WG2	Natural Gas	Yes	4,400	4,200	4,200
	2055	WG3	Natural Gas	Yes	4,400	4,200	4,200
					13,200	**12,600**	**12,600**
Diesel	2050	WD4	diesel	Yes	2,500	2,500	2,500
	2050	WD5	diesel	Yes	2,500	2,500	2,500
	2050	WD6	diesel	Yes	2,500	2,500	2,500
	2050	WD7	diesel	Yes	3,300	3,000	3,000
					10,800	**10,500**	**10,500**

Location	Retirement Year	Original Unit #	Prime Mover Type	Dispatchable	Name Plate Capacity (kW)	Dependable Capacity (kW)	Dependable Capacity (kW)
YEC Diesel Rentals [excluding spares]							
Whitehorse			diesel	Yes	16,200	16,200	16,200
Faro			diesel	Yes	12,600	12,600	12,600
Mayo			diesel	Yes	7,200	7,200	7,200
					36,000	**36,000**	**36,000**
Spares			diesel	Yes	3,600	3,600	3,600
AEY Diesel							
	2050	CD1	diesel	Yes	1,600	1,200	1,200
	2050	TD1	diesel	Yes	1,500	1,200	1,200
	2050	RD1	diesel	Yes	1,000	750	750
	2050	HD1	diesel	Yes	1,750	1,500	1,500
	2050	Pelly G1	diesel	Yes	275	200	200
	2050	Pelly G2	diesel	Yes	600	400	400
	2050	Pelly G3	diesel	Yes	300	200	200
	2050	Stewart G1	diesel	Yes	150	100	100
					7,175	**5,550**	**5,550**
YEC [including rental without spares]				Hydro	95,247	71,138	71,138
				Natural Gas	13,200	12,600	12,600
				Diesel	64,980	59,470	61,970
				Total	173,427	143,208	145,708
AEY				Diesel	7,175	5,550	5,550
Yukon Grid				Hydro	95,247	71,138	71,138
				Natural Gas	13,200	12,600	12,600
				Diesel	72,155	65,020	67,520
				Total	180,602	148,758	151,258
N-1 Dependable Capacity [including rental without spares]				Hydro		34,138	34,138
				Natural Gas		12,600	12,600
				Diesel		63,520	66,020
				Total		110,258	112,758
				DSM		100	500
				Total		110,358	113,258

QUESTION:

a) Please provide the same table of as above [NY-YEC-1-2] updated to show complete generation inventory expected for 2024-25.

ANSWER:

(a)

Please see the response to NY-YEC-1-2.

QUESTION:

Please provide the stacking order for thermal generation – two separate lists:

a) for 2023-24

b) for 2024-25

ANSWER:

(a) and (b)

The generation stacking order changes based on available information at the time of generation, including demand, available resources, system stability requirements, etc.

The following shows the approximate stacking order of thermal units. The stacking order for the 2024/25 winter will be revisited closer to the winter of 2024/25 based on available resources, system stability and condition of thermal units.

The stacking order is subject to (a) total thermal operation at each site not exceeding air emissions permit under normal operation conditions and (b) where feasible, maintain each rental operational hours under 500 hrs/28 days allowance as per contract. It is also important to note that the thermal units are only run when it is required if the other resource options are not adequate to meet the demand on the system.

Type/ Location	**Units**	**Notes**
YEC LNG	WG1, WG2 and WG3	
Whitehorse rentals		
Faro rentals		
Mayo rentals		
YEC Whitehorse diesel	WD4, WD5, WD6, WD7	
YEC Callison diesel	New units	Two 3.25 units potentially available for 2024/25 winter [or 2025/26 winter if delayed]

Type/ Location	Units	Notes
YEC Faro diesel	New units, FD7	Two 2.5 MW new diesel units added for 2024/25 winter
YEC Dawson diesel	DD4, DD3, DD2, DD1	DD2 and DD5 to be retired in 2024
YEC Mayo diesel	MD1, MD2, MD3	

1

REFERENCE: BESS

QUESTION:

a) What is the current status of this project?

b) Is there an estimated completion date?

c) How is this project supported in the current GRA?

ANSWER:

(a) to (c)

Please see response to YUB-YEC-1-44. The project is not currently in the projected costs for test year revenue requirements due to delays that to date prevent the BESS from displacing diesel rental requirements during the test years (see response to YUB-YEC-1-41(b) for review of reasons for delays).

REFERENCE: THELP / Atlin

QUESTION:

a) What is the current status of this project?

b) Is there a new estimated completion date or range of dates?

c) What was the expected completion date in 2020, according to the 10-Year Renewable Electricity Plan? Any other expected completion dates of note?

d) What progress has been made so far? Please provide a list including year and milestone achieved for this project for the last 5 years.

e) Please provide an outline of future milestones – what needs to be done to get this online and when that is expected to occur.

f) How is the future of this project supported in the current GRA?

g) Does YEC expect that there will be another Atlin / THELP EPA hearing due to changing costs or other factors?

ANSWER:

(a) through (e)

Please see response to YUB-YEC-1-44 and YUB-YEC-1-45.

(f)

This project is not included as a rate base addition in the Application as it is not expected to be completed during the test years.

(g)

YEC is not aware of any plans for another hearing.

REFERENCE: **Moon Lake:**

QUOTE: The last thing I have heard about Moon Lake is from the Atlin proceeding:
"Moon Lake pumped storage is a proposed future project that requires material grant funding to complete feasibility studies, as well as to proceed with actual development – its timing, if it proceeds, is likely to be delayed beyond time forecast in the 10-Year Renewable Electricity Plan." (Atlin proceeding, NY-YEC-1-2 REVISED p.3)

QUESTION:

a) Has anything happened since then? What is the current status of this project?

b) What is the new estimated completion date? If this is not available, what is the range? Earliest reasonable completion date and latest?

c) What was the original estimated completion date according to the 10 Year Renewable Plan?

d) Please provide a list of milestones achieved and dates for this project for the last 10 years.

e) Please provide an outline of future milestones – what needs to be done to get this online and when each is expected to occur?

f) How is this project supported in the current GRA?

ANSWER:

(a) through (f)

YEC's 10 Year Renewable Electricity Plan, released in 2020, forecasted a completion date for Phase 1 of the Moon Lake Pumped Storage Project to be 2028/29.

Lack of needed funding and First Nation support resulted in no material advances to date in work on this project. Please see YUB-YEC-1-46(c) for review of parties that expressed

an interest in the project and the necessary consents and approvals required for the project to proceed.

Today, As reported in response to YUB-YEC-1-44, YEC does not have a level of support from First Nation communities to advance early work on this project with confidence that the human and financial resources will be prudent. Therefore, currently, no further work is expected regarding this specific project.

This project is not included as a rate base addition or other costs in the current GRA.

As reviewed in response to YUB-YEC-1-1 (a-c), Yukon Energy is developing an Electricity Supply Plan to update the 10-Year Renewable Electricity Plan and develop a revised workplan for the next 5-10 years for meeting electricity demand during winter peak and N-1 events. The Electricity Supply Plan is expected to be released by mid-2024. It will consider the status of projects proposed in the 10-Year Renewable Electricity Plan, update the near-term forecast capacity and energy gap, and update the plan to meet Yukon's electricity needs in the near-term.

QUESTION:

a) When does YEC anticipate a significant reduction in the number of rental diesels, and are Moon Lake and Atlin expected to be the drivers of this change or are there other options?

ANSWER:

(a)

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

QUESTION:

a) Please provide an updated table of “Number of Diesel Rentals”, which was originally provided by YEC with NY-YEC-1-2 REVISED on pdf p.3 from the Atlin/THELP EPA. Please update to reflect delays in Atlin and Moon Lake and other projects, and note when these projects are expected to be completed. Also please start the table in 2017 or when YEC first rented diesels, as it is useful to be able to chart the growth of the rental diesel fleet.

ANSWER:

(a)

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

QUESTION:

a) What are the most recent 10 renewable projects with a dependable capacity greater than 2MW that YEC has completed? Please provide year, project name and capacity.

ANSWER:

(a)

The most recent renewable projects with dependable capacity are Mayo B hydro units completed in 2011 with 10.6 MW installed capacity and AH 3rd turbine completed in 2011 with 7 MW installed capacity. Please see the response to NY-YEC-1-2 Attachment 1 for details of dependable capacity from these hydro generation units.

All other major hydro facilities were developed primarily in the 1950s - 80s:

- The Whitehorse hydro plant has served Yukoners since 1958 with a third unit added in 1969, and a fourth unit in 1985.

- The Aishihik hydro plant has provided renewable electricity to Yukoners since 1975.

- The Mayo A hydro facility has served Yukoners since 1951.

QUESTION:

a) Are there any other renewable or sustainability oriented projects of note that YEC is pursuing if Atlin and Moon Lake are further delayed or canceled? What are the next 5 renewable projects greater than 2 MW dependable capacity other than BESS, THELP/Atlin and Moon Lake? Please provide lead times and best guess as to expected completion dates, current status, MW dependable capacity and the name of the project.

ANSWER:

(a)

Yukon Energy is undertaking two planning exercises that will identify future renewable resource options in the territory and the key investments required to increase the supply of winter capacity and energy, decrease demands for power, and upgrade the Yukon's existing electricity system.

1. **Short-term Electricity Supply Plan:** This plan will identify resources that can be developed in the next 5-10 years. It is expected to be released by mid-2024.

2. **Long-term Resource Plan:** This plan will identify resources that need more time to be developed. It will contemplate technologies that are commercially available today and technologies that are still emerging. It will also contemplate the potential of an intertie with British Columbia as one potential long-term resource. This plan is expected to be ready in late 2025.

REFERENCE: **Whitehorse Thermal Permitting**
It is first noted that Section 9 of the Air Emissions Permit expired on March 31, 2022. Section 9 had allowed 12MW of rental diesel in N-1 conditions.

QUESTION:

a) What is the current permitted diesel generation capacity limit for the WGS? Undertaking #29 from the 2021 GRA (PDF p251 of Undertakings Final) indicates YEC considers this to be 14MW. Looking at capacities from the most recent assessment of WD3 thru WD7 (YESAB 2011-0241 p.9) the last assessed capacity of the 5 generators mentioned adds up to a total permitted capacity of 13.75 MW, which YEC is then rounding up to 14 MW. Is this correct?

b) What is the currently installed dependable capacity for diesel at the WGS, including installed and rented generators, in regular and in N-1 conditions?

c) What relevant actions has YEC taken since the expiration of Section 9 of the permit? Has YEC checked with the Regulator, the Department of Environment to understand the ramifications of the expiration of this section? Please provide all correspondence between YEC and the Department of Environment concerning the expiration of Section 9 of the Whitehorse air emissions permit, and and the ability to run more than 14MW and rental diesel after March 31, 2022.

d) In March of 2023, Yukon Energy held public meetings concerning the renewal of their thermal permit which expires in 2024 and indicated that a YESAB assessment would be starting in Fall of 2023. Is this still on schedule? Will YEC be asking for capacity other than the 14MW currently permitted?

ANSWER:

(a)

Assessed (YESAA Project Assessment 2013.0115) and permitted Whitehorse diesel generating under normal operating conditions is 16.15 MW.

As reviewed with the Board in the 2021 GRA, permitting constrains normal operation limits but does not constrain YEC's ability to have available and use additional diesel generating capacity for use if needed in emergency conditions.

As indicated in the Application, the Air Emissions permit limits normal operations to a certain capacity without limiting actual available capacity or capacity operation during an N-1 event to protect public health and safety. Under Section 49 of the Yukon Environmental and Socio-economic Assessment Act, YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety which the YUB agreed to in Order 2022-03 (para 110) stating that "… N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in interest of public welfare, health or safety."

While YEC understands there are provisions in YESAA to preclude the need for an assessment in the case of an emergency, there are no such provisions in the Environment Act or Air Emissions Regulations. As such, Yukon Energy would communicate with the Authority Having Jurisdiction (AHJ) for air emissions (Yukon Government – Environment Department) in the case of a requirement or occasion where any particular generating station anticipated exceeding or did in fact exceed its permitted operating capacity. Yukon Energy would address any requirements of the AHJ under such circumstances to the best of its ability.

(b)

Please see response to NY-YEC-1-2 Attachment 1.

(c)

As is typical of previous permit renewals for this facility, the Corporation has been conducting studies related to potential air quality, human health, and noise impacts from the facility. Engagement with assessors, regulators, First Nations governments, community associations, the City of Whitehorse, other key stakeholders and the public regarding the continued operation of the project has also been undertaken. Yukon Energy understands that the production capacity under normal operating conditions allowed under its current air emissions permit is limited to 13.2 MW of natural gas and 16.15 MW of diesel. A restoration of the previous permit allowance for an additional 12MW diesel for

emergency use is being sought as part of the YESAA assessment and air emission permit renewal required before the existing permit expires at the end of 2024.

(d)

The Project Description for the YESAA assessment required to renew the authorizations for some of the activities associated with thermal generation at WRGS was submitted in early November 2023. Yukon Energy is requesting renewal of the previously authorized normal production capacity (13.2 MW of natural gas and 16.15 MW of diesel) with a restoration of the previous allowance for an additional 12MW diesel capacity for emergency use. Other activities, such as those associated with the handling and storage of natural gas, are authorized until 2054 and do not require assessment and authorization renewal at this time.

REFERENCE: **Whitehorse Thermal Permitting additional questions on noise and efficiencies:**

QUESTION:

a) Given that the 2020 Noise Monitoring Assessment for the WGS acknowledged that sound levels were higher than allowed by BC OGC and Health Canada, what progress (if any) has been made towards Yukon Energy's stated commitment to: "Explore possible ways to reduce noise levels at the Whitehorse diesel plant. This may include adding equipment to the generators to muffle noise, making changes to the building or other options."

b) What are the noise levels of the permanent/installed diesel generators compared to the rentals? Please provide a comparison of noise produced by all of the installed/permanent generators running at the same time (9.55MW) vs the noise from 9.55 MW produced exclusively by the rentals.

c) What are the generating efficiencies of the installed diesels compared to the rentals? Please provide a comparison of fuel consumption at 9.55 MW using the installed/permanent generators vs fuel consumption of the rentals to produce the same output? Fuel usage per MWh would also be useful.

d) Please provide a comparison of NO2 and other pollutants at similar capacities – Installed vs rental units.

e) Has YEC considered moving its diesel generation to a different location further from residences, particularly given that rental diesel is expected to be required for many years? While I realize relocation costs will be high, I am guessing that a YESAB assessment increasing capacity to 26 MW or more in this location will also be challenging.

f) There were a number of issues with the 2020 sound monitoring report which remain unaddressed, from missing baseline measurements to classification of Bell Crescent as “urban” rather than “suburban” to indicating that it was quieter when the generators were running than when they were not.
The report uses Health Canada guidelines to calculate “High Annoyance” based on changes in noise levels. Amazingly, the 2020 sound monitoring report

concluded that the noise from the diesel generators would actually decrease annoyance of nearby residents in comparison with the baseline of the generators not running – which was said to be louder. Wait… diesel generator noise makes things quieter and makes people happier?

While YEC's diesel happiness generators are an interesting concept, a report that reaches this conclusion cannot be taken seriously.

When will a new and ideally less comically flawed sound monitoring report be available?

ANSWER:

(a)

Sound level monitoring has been ongoing at the WRGS since 2020. Additional assessment work on the ambient and operational period sound level recordings indicates that the existing permanent diesel units located in the diesel plant (P126) at the WRGS are the principal sources of operational noise that might irritate the Riverdale residential area. The east side of the P126 building exposes the combustion air intakes and engine exhaust components of WD4-7 to nearby Riverdale and has the largest source of sound from thermal operations at the Project Site.

As part of diesel capacity replacement and fuel system upgrades that will be occurring at WRGS over the next two years, Yukon Energy will install sound attenuating equipment on the east side of P126 to reduce sound levels when WD4-7 are running.

(b)

Scenario Description	Sound Levels Measured at Riverside Substation[1]
Daytime Noise Level when operating WD4-7 (10.5 MW)	61.0 to 63.9
Daytime Noise Level When Operating Eight Rental Units (14.4 MW)	49.7 to 54.3

Notes: [1] All sound levels in dBA. Measured continuously from November 2020 to October 2021.

(c)

Summary of Pre-Tier and Tier 2 Fuel Efficiency

Generator	Estimated Fuel Efficiency (L/kWh)
Average Pre-Tier Engines (WD4-7)	~650
Average Tier 2 Engines (Rental Units)	~400

(d)

Summary of WRGS Generator Emission Factors (g/kwh)

Engine ID	TSP	PM2.5	PM10	NOX	NO2	NO	CO	SO2
WG1	0.04	0.02	0.04	1.851	0.346	0.982	4.06	0.003
WG2	0.04	0.02	0.04	1.851	0.346	0.982	4.06	0.003
WG3	0.04	0.02	0.04	1.851	0.346	0.982	4.06	0.003
WD4	0.426	0.199	0.215	13.25	1.1	7.92	0.729	0.021
WD5	0.426	0.328	0.37	12.01	0.997	7.18	0.209	0.022
WD6	0.426	0.325	0.348	12.21	1.014	7.3	0.114	0.019
WD7	0.426	0.053	0.06	7.12	0.591	4.26	0.208	0.004
WD8/9[1]	0.027	0.027	0.027	0.67	0.056	0.401	0.67	0.017
Rental Diesels	0.04	0.04	0.04	6.06	0.503	3.62	0.49	0.017

Note: [1] Planned EPA Tier 4 replacement capacity for WD3

(e)

In 2019, five locations were explored for the potential development of a new 20 MW thermal facility: beside YEC's Takhini substation; near the Whitehorse sewage lagoon; at the Whitehorse landfill; at YEC's existing diesel plant in Whitehorse; and across the street from YEC's Whitehorse LNG plant.

Following this work, a decision was subsequently made by Yukon Energy's Board of Directors to look at ways to avoid building a single new 20 MW liquefied natural gas (LNG) or diesel facility and instead look at options to add or replace capacity at existing YEC generation facilities as its fleet of diesel engines retire.

(f)

YEC received further analysis from Hemmera Envirochem Inc. in 2021 (see Attachment 1 to this response).

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November 18, 2021
File No. 104873-02

Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: Shannon Mallory, Environment and Resource Analyst

Re: Noise Monitoring at the Whitehorse Rapids Generating Station

1.0 INTRODUCTION

Yukon Energy Corporation (YEC) operates the Whitehorse Rapids Generating Station, located on Miles Canyon Road in Whitehorse, Yukon. Much of the power is generated using hydroelectric facilities but diesel generating units are used for backup to meet energy demand. Due to the potential for noise impacts associated with operation of the diesel generating units at the nearest residences in the Riverdale subdivision, YEC engaged Hemmera Envirochem Inc. (Hemmera) to install a long-term noise monitoring station at the Riverside Substation and to evaluate noise mitigation options at the Whitehorse Rapids Generating Station.

This Work was performed in accordance with Consulting Contract 20077 between Hemmera, a wholly owned subsidiary of Ausenco Engineering Canada Inc. (Ausenco), and YEC (Client), dated October 6, 2020 (Contract). This Report has been prepared by Hemmera, based on fieldwork conducted by Hemmera, for sole benefit and use by YEC. In performing this Work, Hemmera has relied in good faith on information provided by others, and has assumed that the information provided by those individuals is both complete and accurate. This Work was performed to current industry standard practice for similar environmental work, within the relevant jurisdiction and same locale. The findings presented herein should be considered within the context of the scope of work and project terms of reference; further, the findings are time sensitive and are considered valid only at the time the Report was produced. The conclusions and recommendations contained in this Report are based upon the applicable guidelines, regulations, and legislation existing at the time the Report was produced; any changes in the regulatory regime may alter the conclusions and/or recommendations.

2.0 FACILITY DESCRIPTION

Specifications of the diesel generators located at the Whitehorse Rapids Generating Station are presented in **Table 2.1**. There are four main units located inside the generator building, and ten rental units located outdoor west of the building, contained within individual C-Cans. While the total rated power at the Whitehorse Rapids Generating Station is 28.5 megawatts (MW), the maximum allowable capacity as per facility permitting is 14.6 MW.

Table 2.1 Diesel Generator Specifications

Unit ID	Model	Rated Power (MW)
WD4	EMD 645	2.5
WD5	EMD 645	2.5
WD6	EMD 645	2.5
WD7	Caterpillar 3516	3.0
YM1 to YM10	Caterpillar XQ2000	1.8

3.0 REGULATORY GUIDANCE

In the absence of any specific regulatory guidance or criteria in the Yukon for generating stations, this assessment considers the BC Oil and Gas Commission's Noise Control Best Practices Guideline (BC OGC 2018) and Health Canada's Guidance for Evaluating Human Health Impacts in Environmental Assessment (Health Canada 2017).

The BC OGC guideline is widely accepted in western Canada and commonly used in the Yukon. The guideline, which sets out permissible sound levels (PSLs) at receptors or residences, strikes a balance between the need to accommodate development and the need to control noise emissions from the energy industry. PSLs are established based on the local dwelling density and proximity to heavily travelled transportation routes. There are PSLs for the daytime period (i.e., 7:00 am to 10:00 pm) and the nighttime period (i.e., 10:00 pm to 7:00 am), both expressed in A-weighted decibels (dBA) which represents the relative loudness perceived by the human ear. For the nearest residences in the Riverdale subdivision, the daytime PSL is 61 dBA. Since the Whitehorse Rapids Generating Station only operates during daytime hours, nighttime PSLs are not applicable.

The Health Canada guidance does not prescribe specific noise thresholds but rather provides indicators that consider potential health risks due to exposure. For continuous noise such as those from generating stations, percent of high annoyance (%HA) is used to provide information on aggregate community response to various noise levels. A facility-related change in the %HA greater than 6.5% is deemed to represent a severe noise impact for which noise mitigation measures should be considered.

4.0 BACKGROUND

Due to a combination of low water levels, increased demand, and outage of a natural gas generating unit at the Whitehorse Rapids Generating Station, YEC was required to run diesel generators to meet energy demand in April 2020. Hemmera conducted short-term noise monitoring at three locations for approximately 24 hours at each location to understand noise levels associated with the operation of the diesel generators.

The measured daytime noise level on April 22, 2020 at the Riverside Substation (see **Figure 1**) was 66 dBA, which exceeded the PSL of 61 dBA from the BC OGC. Relative to baseline conditions, the change in %HA at the Riverside Substation on April 22, 2020 was 8.8%, which exceeded Health Canada's guideline of 6.5%.

Measured noise levels on April 23, 2020 at a residential location on Bell Crescent remained below the BC OGC PSL as well as Health Canada's guideline for %HA.

Overall, short-term noise monitoring in April 2020 suggested that operation of the diesel generators at the Whitehorse Rapids Generating Station may result in exceedances of the noise guidance criteria at the nearest residences in the Riverdale subdivision.

5.0 LONG-TERM NOISE MONITORING

5.1 Monitoring Goals

A project kick-off meeting was held with YEC project representatives on October 16, 2020 to discuss program objectives. A site visit was conducted on November 9, 2020 to review siting requirements. To provide the monitoring station with continuous power, it was decided that the best location was adjacent to the main building located at the southeast corner of the Riverside Substation (see **Figure 1**). Spot measurements were taken to ensure that any noise contribution from substation building operations would be minimal and that collected noise data would be representative of overall noise levels in the Riverdale subdivision.

5.2 Procurement and Installation of Monitoring Station

A long-term noise monitoring station was procured on behalf of YEC and installed at the Riverside Substation on November 19, 2020. The long-term noise monitoring station comprises a Bruel and Kjaer 3639 noise monitoring terminal, a general purpose instrument designed for continuous unattended outdoor noise monitoring that meets Class I specifications from International Standard IEC 61672.

5.3 Programming

The noise monitoring station is connected via cellular modem to Bruel and Kjaer's Sentinel system[1], a web-based application where noise monitoring stations can be controlled, and where data can be stored, displayed and exported. The Sentinel system was programmed to provide alerts and record sound clips when noise levels exceed the BC OGC PSL of 61 dBA.

5.4 Review of Sound Data

A summary of the long-term noise monitoring data from November 19, 2020 to October 31, 2021 is presented in **Table 5.1** along with the short-term noise monitoring data from April 2020 at the Riverside Substation. During the November 2020 to October 2021 timeframe, daytime noise levels reached a maximum of 61 dBA, equivalent to the BC OGC PSL, on three occasions (May 18, July 6, and August 5, 2021). On these three days, the Whitehorse Rapids Generating Station did not operate any diesel generating units and measured noise levels are related to general community noise (e.g., construction).

[1] Currently owned by Envirosuite who acquired Bruel and Kjaer in 2020.

Table 5.1 Summary of Noise Monitoring Data

	Long-Term Noise Monitoring (Nov 2020 – Oct 2021)	Short-Term Noise Monitoring (Apr 22, 2020)
Daytime noise level (7:00 am to 10:00 pm)	45.8 to 61.0	66.4
Nighttime noise level (10:00 pm to 7:00 am)	41.2 to 58.0	56.6
Day-night noise level	46.9 to 64.5	66.5

Note: All values are shown in dBA. Excludes periods of equipment malfunction from November 24 to December 15, 2020 and February 28 to March 2, 2021. Also excludes data on June 22 to 24, 2021 when temporary service work was being conducted at the Riverside substation, resulting in unusually high noise levels.

Overall noise levels for operation of the main generating units WD4 to WD7 versus operation of the rental generating units is presented in **Table 5.2**. Noise levels are significantly higher with the operation of the main generating units WD4 to WD7.

Table 5.2 Noise Levels for Main versus Rental Generating Units

	Long-Term Noise Monitoring (Nov 2020 – Oct 2021)	Short-Term Noise Monitoring (Apr 22, 2020)
Daytime noise level with WD4 to WD7 operating	61.0 to 63.9	66.1
Daytime noise level with eight rental units operating	49.7 to 54.3	-

Note: All values are shown in dBA. Values represent average noise levels over the course of a day and do not include potential spikes in noise levels.

As shown in **Table 5.1** and **Table 5.2**, measured noise levels on April 22, 2020 were perceptibly higher (i.e., up to 5 dBA higher) than the measured noise levels from November 2020 to October 2021.

5.4.1 Facility Testing

Further analysis was conducted to understand the difference in noise levels in April 2020 as compared to the period from November 2020 to October 2021. Upon initial review, the following facility characteristics were expected to have contributed to the measured differences in noise levels:

- There is a small door located along the east wall near WD7. Based on photographs taken in April 2020 (see **Appendix A**), this door was open during the time of the short-term monitoring.
- A bay door separates WD7 in the Cat bay from WD4 to WD6 in the EMD bay. Based on conversations with YEC staff, it is understood that this bay door may be left open, resulting in higher noise levels at the exterior door noted above.
- There are two operable fresh air intakes along the east wall near WD7. Based on photographs taken in April 2020 (see **Appendix A**), these intake louvres were open during the time of the short-term monitoring program.

Testing was conducted on October 20, 2021 to confirm noise levels associated with operation of all four generating units WD4 to WD7, with and without the exterior door, bay door, and fresh air intakes open. Results of the facility testing are outlined in **Table 5.3**, which suggests that the exterior door and fresh air intakes can contribute to a 1 dBA difference in noise levels at the Riverside substation. The bay door does not appear to contribute to any measurable difference in noise levels at the Riverside substation.

Table 5.3 Breakdown of Noise Monitoring Data by Activity

	Measured Noise Level (dBA)
Exterior door, bay door, fresh air intakes closed	63.8
Exterior door, fresh air intakes open	64.7
Exterior door, bay door, fresh air intakes open	64.4

5.4.2 Weather and Seasonality

Long-term noise monitoring data from November 2020 to October 2021 was analyzed to discern any trends with respect to weather such as ambient temperature and relative humidity. As illustrated in **Figure 2**, no obvious trends were observed. This agrees with a general understanding of noise propagation principles. Noise propagation is driven by temperature and wind gradients, rather than the actual wind speed or ambient temperature. Sound energy tends to be bent downwards during temperature inversions (i.e., when the temperature near the ground is lower than that of the upper air) and downwind conditions, thus resulting in somewhat higher sound levels at ground-level. While the relative humidity of the air can result in minor changes to atmospheric absorption of noise, this is most pronounced at very low humidity levels (e.g., 10 to 20%). Effects on atmospheric absorption is negligible at the humidity range observed in Whitehorse (i.e., 40 to 80%).

Another factor that may contribute to differences in noise levels between April 2020 and the period from November 2020 to October 2021 is ground effect, the degree to which the ground surface absorbs or reflects sound energy. Pavement and hard-packed snow and ice tends to reflect sound energy and increase noise levels whereas grass and soft snow tends to absorb sound energy and reduce noise levels. Based on photographs taken in April 2020 (see **Appendix A**), pavement was bare and hard-packed snow and ice covered grass areas which may have contributed to higher noise levels during this time. This phenomenon is considered in noise propagation modelling (see **Section 6.0**) using a parameter G which varies from 0 representing reflective surfaces to 1 representing absorptive surfaces.

6.0 NOISE MODELLING

Noise propagation modelling was conducted using the DataKustik CadnaA model to estimate potential maximum noise levels associated with operation of the diesel generators at the Whitehorse Rapids Generating Station. The CadnaA model calculates outdoor sound propagation based on international standard ISO 9613-2 and considers maximum noise effects under downwind conditions and moderate temperature inversions. ISO 9613-2 accounts for the following factors:

- Sound power levels, duration, and timing of emission sources: This assessment considers continuous operation of diesel generating units during daytime hours.
- Distance attenuation: Two discrete receptors were specified in the model, one at the long-term noise monitoring location at the Riverside Substation, and one at the nearest residence in the Riverdale subdivision, as illustrated in **Figure 1**.
- Source-receptor geometry including relative heights: A receptor height of 1.5 m is considered to reflect human exposure to noise.

- Meteorological effects: The approximate average springtime values for Whitehorse of 10°C and 70% relative humidity were used in the model to capture worst-case conditions when the diesel generators at the Whitehorse Rapids Generating Station are likely to operate. This is similar to conditions experienced at the time of short-term noise monitoring in April 2020 although meteorological effects are expected to have minimal influence on overall noise levels as described in **Section 5.4.2**).
- Ground effect: Noise modelling considered a parameter G of 0 representing reflective surfaces such as pavement and hard-packed snow and ice as well as a parameter G of 1 representing absorptive surfaces such as grass and soft snow.

The following scenarios were considered in the noise modelling:

- Scenario 1: Operation of WD4 to WD7, with doors and intake louvres closed, and a parameter G of 1. This is expected to correspond to wintertime conditions during the long-term noise monitoring from November 2020 to October 2021.
- Scenario 2: Operation of WD4 to WD7, with doors and intake louvres open, and a parameter G of 0. This is expected to correspond to springtime conditions during the short-term noise monitoring in April 2020.
- Scenario 3: Operation of WD4 to WD7 plus two rental units, for a total capacity of 14.4 MW. This represents a peak operating scenario which is slightly under the maximum permitted capacity of 14.6 MW for the facility. Doors and intake louvres are open, and a parameter G of 0 is used to consider worst-case effects.
- Scenario 4: Operation of eight rental units, for a total capacity of 14.4 MW. A parameter G of 0 is used to consider worst-case effects.
- Scenario 5: This is the same as Scenario 3 above except with a recommended noise wall/barrier (see below).

A summary of modelled noise levels is presented in **Table 6.1**. Noise levels at the Riverside Substation may exceed the BC OGC PSL of 61 dBA if WD4 to WD7 are operating continuously during daytime hours. The change in %HA may also exceed the Health Canada threshold of 6.5% during worst-case conditions if doors and intake louvres are open, and ground surfaces are completely reflective. Noise levels with continuous operation of the eight rental units are expected to be substantially lower, remaining below the guidance criteria.

At the nearest residence in the Riverdale subdivision (approximately 60 m beyond the Riverside Substation), noise levels may exceed the PSL if WD4 to WD7 are operating continuously during worst-case conditions, with doors and intake louvres open, and reflective ground surface. The change in %HA may also exceed the Health Canada threshold of 6.5% at the nearest residence in the Riverdale subdivision during maximum permitted operation of two rental units in addition to the four main units.

To achieve compliance with the BC OGC and Health Canada guidance criteria during worst-case conditions, the following mitigation measures are recommended:

- Operate the rental generating units in place of WD4 to WD7 where practical.
- Install a noise wall/barrier of 8-metre height in front of the east wall, enclosing the generator stacks and air coolers (see **Figure 1**). The wall/barrier should be continuous without holes, gaps and other penetrations, and should have a surface mass density of at least 20 kilograms per square metres.[2]

Table 6.1 Summary of Noise Modelling Results

	Riverside Substation		Nearest Residence	
	dBA	%HA	dBA	%HA
Scenario 1	**62.2**	3.6	59.5	1.8
Scenario 2	**67.7**	**10.2**	**64.5**	5.9
Scenario 3	**69.6**	**13.4**	**66.5**	**8.4**
Scenario 4	60.7	2.5	60.1	2.1
Scenario 5	59.1	1.6	57.8	1.0

Note: Noise levels shown include an average background level of 54.9 dBA in the daytime and 49.5 dBA at night based on long-term noise monitoring from November 2020 to October 2021. Values in bold font exceed the BC OGC Health Canada guidance criteria.

7.0 CONCLUSIONS AND RECOMMENDATIONS

Daytime noise levels during the long-term noise monitoring from November 2020 to October 2021 remained below the BC OGC PSL. However, previous noise monitoring in conjunction with noise modelling suggests that noise levels at the nearest residence in the Riverdale subdivision may exceed BC OGC and Health Canada guidance criteria during worst-case operations with doors and air intakes open, and ground surfaces are completely reflective. Operation of the rental generating units are associated with significantly lower noise levels compared to operation of the main generating units.

It is recommended that the following noise mitigation measures be implemented to reduce noise levels in the Riverdale subdivision to below guidance criteria:

- Operate the rental generating units in place of WD4 to WD7 where practical.
- Install a noise wall/barrier of 8-metre height in front of the east wall.

[2] Based on iterative noise modelling, the minimum required barrier height for achievement of specified noise guidance criteria is 8 metres. Characteristics of the barrier are specified to ensure that the sound component transmitted through the barrier is at least 10 dBA below the sound component diffracted across the top of the barrier (City of Ottawa 2016).

8.0 CLOSURE

We have appreciated the opportunity of working with you on this project and trust that this report is satisfactory to your requirements. Please feel free to contact the undersigned regarding any questions or further information that you may require.

Report prepared by:
Hemmera Envirochem Inc.

Nancy Chan, B.A.Sc., P.Eng.
Acoustic Specialist

Mark Milner, M.Eng., P.Eng.
Project Director

9.0 REFERENCES

British Columbia Oil and Gas Commission (BC OGC). 2018. British Columbia Noise Control Best Practices Guidelines. Version 2.1.

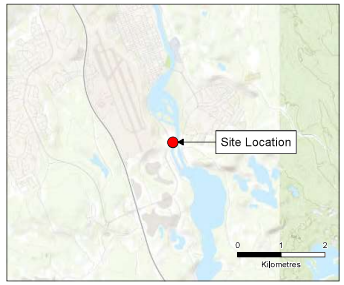
City of Ottawa. 2016. Environmental Noise Control Guidelines, Part 5 : Technical Requirements for Acoustic Barrier Systems.

Health Canada. 2017. Guidance for Evaluating Human Health Impacts in Environmental Assessment: Noise.

FIGURES

Noise Monitoring at the Whitehorse Rapids Generating Station
2 Miles Canyon Road, Whitehorse, YT

Site Location



Legend

- Noise Monitoring Location
- Nearest Residence
- Noise Wall
- Property Line

Notes

1. All mapped features are approximate and should be used for discussion purposes only.
2. This map is not intended to be a "stand-alone" document, but a visual aid of the information contained within the referenced Report. It is intended to be used in conjunction with the scope of services and limitations described therein.

Sources

- Contains information licensed under the Open Government Licence - Yukon Territory
- Aerial Image: ESRI World Imagery
- Inset Basemap: ESRI World Topographic Map

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0 20 40 60 80 100
Metres

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Page Size: 11" x 17"

104873-02	Production Date: Nov 16, 2021	Figure 1

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An Ausenco Company

Yukon Energy Corporation

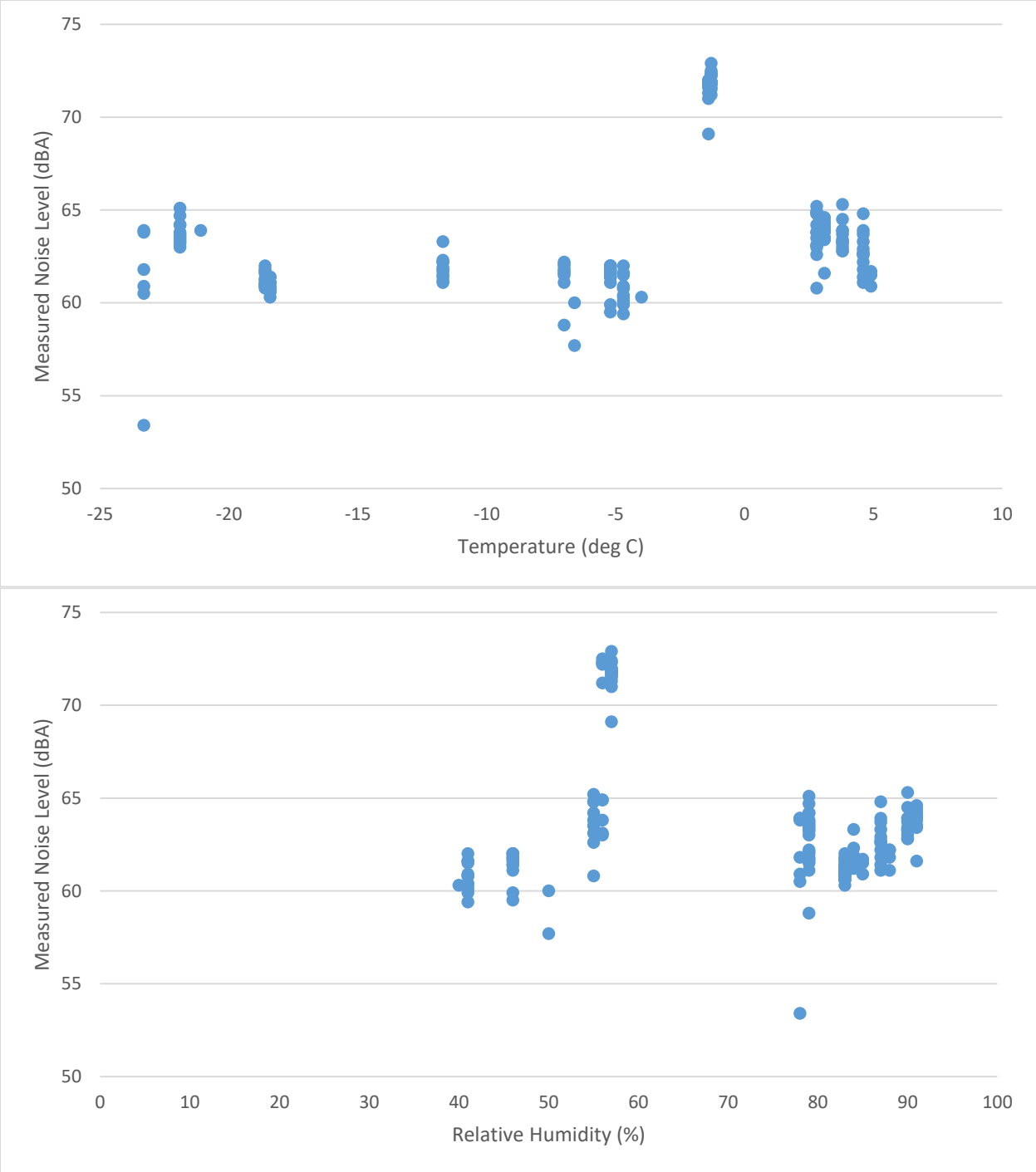


Figure 2 Dependence of Measured Noise Levels with Temperature (top) and Relative Humidity (bottom)

APPENDIX A
Photographs

Photo 1 View from east, main generating unit exhaust stacks

Photo 2 Main generating unit WD6 inside building

Photo 3 View from southwest, rental generating units

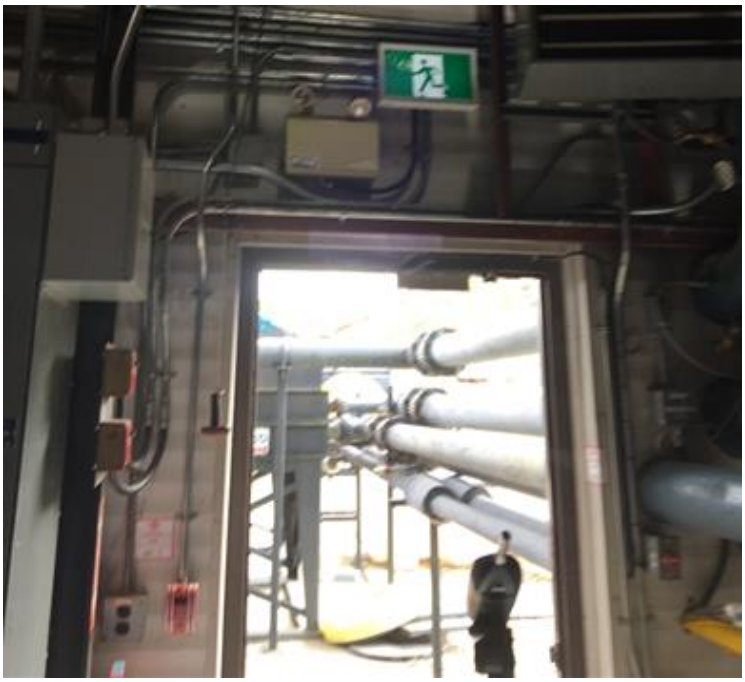


Photo 4 Exterior door near WD7

Photo 5 View of fresh air intake louvre (open position) from outside

Photo 6 View of fresh air intake louvres (open position) from inside

Photo 7 Hard-packed snow and ice outside generator building

REFERENCE: Faro diesel replacement, modifications to the FGS

QUESTION:

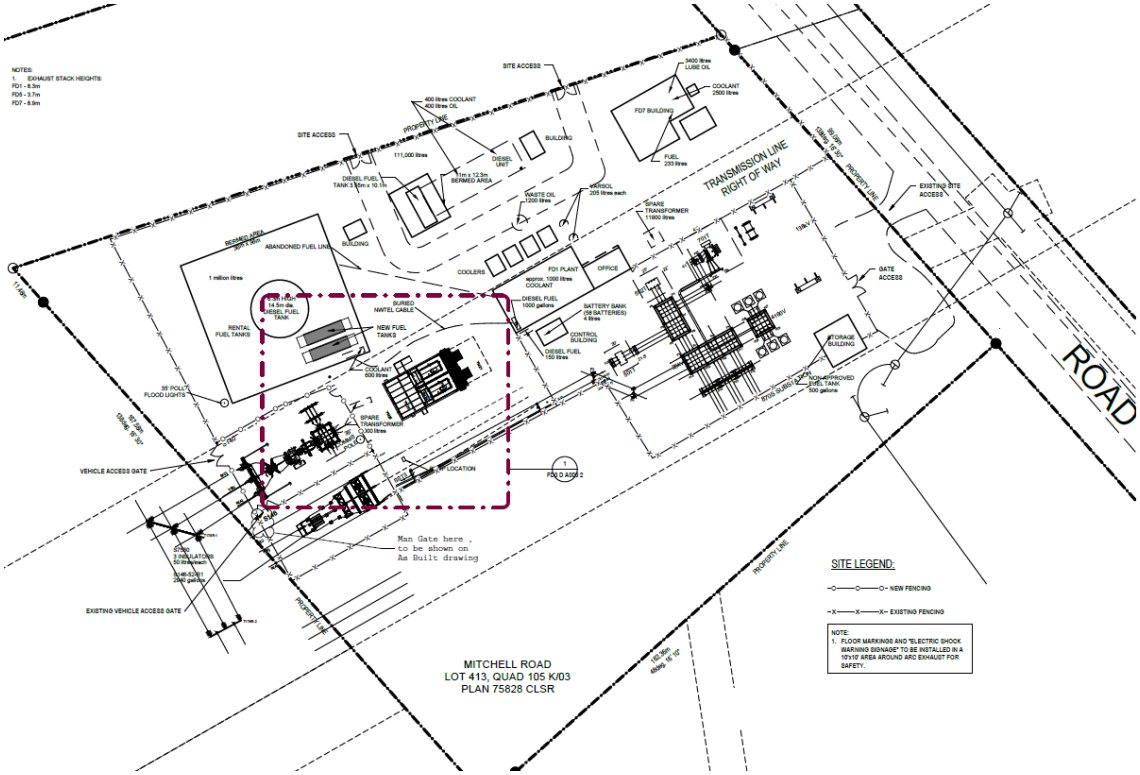
a) Please provide all plans, layouts, specifications, studies (noise, emissions, etc) and all other documentation relating to the modifications (2023 and 2024) to the FGS. This would also include plans, requirements and instructions given to contractors and subcontractors. Also please provide a list of contractors and subcontractors and RFPs.

b) Please provide all correspondence between YEC and the Department of Environment concerning the 2023 and 2024 modifications to the FGS.

ANSWER:

(a)

YEC is installing two Tier 4 engines of 2.5MW each. The layout of the site is as follows:



Contractors and subcontractors include:

- General Contractor (general construction, supervision, mechanical install, civil construction) – Wildstone Construction Group;
- Major Equipment Supplier and Commissioning Agent – Finning;
- Electrical Subcontractor – Westpark;
- Tank and mechanical material supplier – Keller;
- Formwork and reinforcing steel subcontractor – A&T;
- Concrete supplier – General Enterprises;
- Concrete finishing subcontractor – JLB;
- Containment subcontractor – Albarrie;
- Fencing subcontractor – Olson Fencing.

(b)

The 2023 email thread between T. Ritchie (YEC) and Elizabeth Barker (Yukon Government) regarding the FGS is included as NY-YEC-1-14(b) Attachment 1. The 2023 email thread between T. Ritchie (YEC) and Emily Sessford (Yukon Government) is included as NY-YEC-1-14(b) Attachment 2.

From: Elizabeth.Barker
To: Travis Ritchie
Subject: RE: [EXT] RE: Faro Station Modifications
Date: February 20, 2023 9:17:11 AM
Attachments: image002.png
image003.png
image004.png
image005.png
image006.png
image007.png

Hi Travis,
I appreciate the additional context around YEC's operations. It's good to hear the permit capacity is built into the system controls.

I'd like to let you know that based on the information received to date, the proposed changes to the Faro station are not considered YESAB assessable. We will further evaluate and confirm this decision once we're received formal notification and more details from YEC.

Thanks,
Liz

Elizabeth Barker
Environmental Protection Analyst
Environment | Standards and Approvals
T 867-667-5456 | Yukon.ca

From: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Sent: Thursday, February 16, 2023 10:00 AM
To: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Subject: RE: [EXT] RE: Faro Station Modifications

Hi Liz,

Thanks for your note.

For context, we are still responding to evolving operational needs and community concerns in Faro, so are only in the planning phase of any potential changes. Recent dialogue with the municipal government and residents in the Town of Faro is part of the engagement we are undertaking during this phase. Once we have a draft plan crystallized we had planned to engage your team for review and approval of the potential changes, so we will make sure Part 2, Item 5 of the permit is followed once we reach that point.

Regarding permitted operational capacity I wanted to share that the System Operators are familiar of our permit thresholds and have these rules built directly into their system controls. Any attempt to dispatch more generation at a facility beyond its permitted capacity prompts an alarm that annunciates to the Operator so that we maintain compliance with this permit requirement. As you may know, YEC maintains installed capacity at several of its thermal generating stations that exceeds

the operational thresholds allowed by the air emissions permits. This redundancy ensures if any units fail to start when called upon, that we have sufficient back-up resources to meet system demands. In any extraordinary circumstances where we may have an emissions exceedance we would notify your office and that of the Compliance and Inspections Unit forthwith.

Hope this additional context is helpful.

Thanks again.

Regards,

Travis

From: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Sent: February 16, 2023 8:37 AM
To: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Subject: RE: [EXT] RE: Faro Station Modifications

Hi Travis,
Thanks very much for the responses. While I recognize that you have provided information about the proposed modification below, I'll still ask that prior to making any modifications at the Faro station, please send me an official notification and wait until we have approved the modifications before proceeding with them, as per Part 2.5 of the current permit as shown below.

5. The permittee shall obtain approval from an environmental protection analyst prior to:
a) any addition, modification, removal or replacement of any equipment or components related to the release, abatement, control or treatment of air emissions; or
b) any change in location of the source(s).

Additionally, as you are aware, the Faro station was assessed and permitted for a capacity of 15.5MW. Operation above a capacity of 15.5MW will result in non-compliance and could result in further enforcement action.

Thanks again for the quick response and I'll be in touch regarding the complaint management plan.

Cheers,
Liz

From: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Sent: February 14, 2023 2:47 PM
To: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Cc: Lisa Wiklund <lisa.wiklund@yec.yk.ca>
Subject: RE: [EXT] RE: Faro Station Modifications

Hi Liz,

Sorry for the delay. Please see my response embedded below.

Please let me know if you need anything further or would like to discuss.

Regards,

Travis

From: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Sent: February 14, 2023 1:54 PM
To: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Cc: Lisa Wiklund <Lisa.Wiklund@yec.yk.ca>
Subject: RE: [EXT] RE: Faro Station Modifications

Hi Travis,
I need to write a response this week and I was hoping you could answer the following questions?
Are all of the following modifications going to occur at the Faro station: **RESPONSE: Yes**

- Decommissioning FD1 – Mirrlees KV16 Generator
- Adding two new "permanent" generators, FD8 and FD9.
- Moving 3 "temporary" rental generators and infrastructure to a different location in the facility.
- Removing 2 "temporary" rental generators.
- Possible addition of sound barriers around FD7 and/or two of the rentals

If yes…
What is the nameplate capacity and tier of FD8 and FD9?

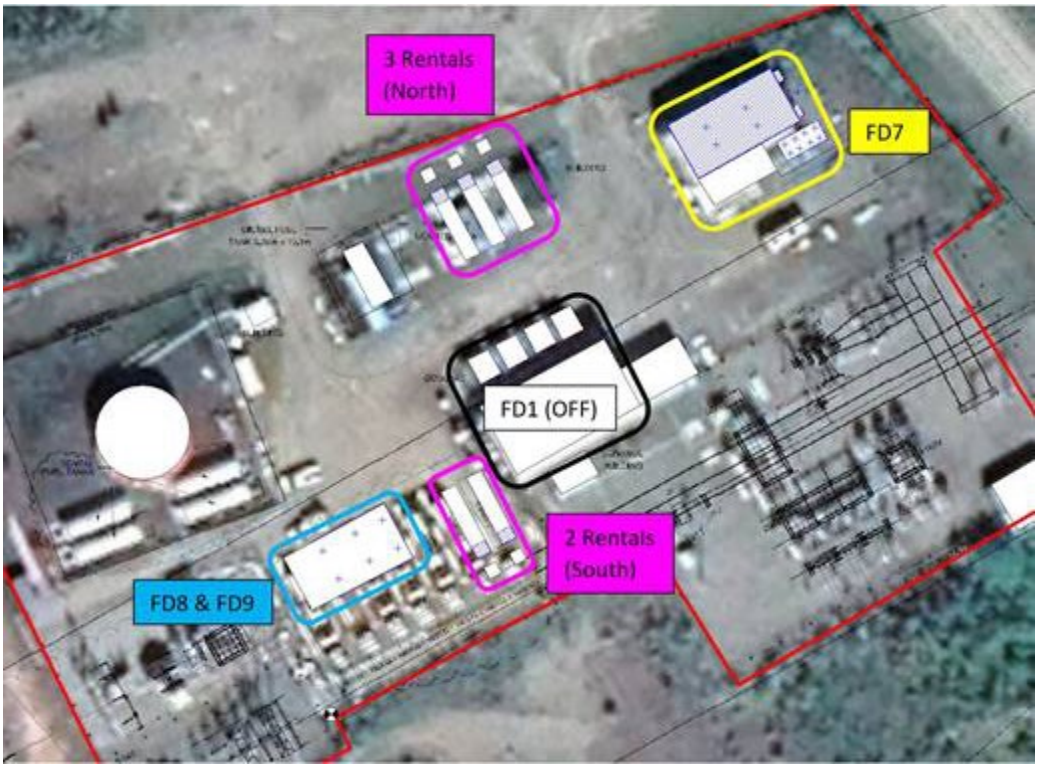
RESPONSE: FD1 is now end of life and we are planning to replace that permitted capacity with 2 x ~2.5 MW EPA Tier 4 and CARB certified diesel generators. This represents an investment by YEC in 'best available technology' and will result in reduced noise and criteria air contaminant (CAC) emissions from the existing Pre-Tier FD1 unit (1960's technology). FD1 represents 5.15 MW of the capacity at the FGS.

Which temporary generators are being removed?

RESPONSE: A portion of the capacity installed at the FGS is made up of rental units (currently 7 x 1.8 MW) that are in place as backup in case any other unit fails to start or is down for planned/unplanned maintenance or repair when the capacity is needed. We anticipate that with the installation of FD8 and FD9, to replace the less reliable FD1, this will allow us to remove two (2) of the seven (7) rental units of this redundant capacity at site in the near term. The temporary rental generators are as described in our previous assessment and permitting documentation (i.e., Caterpillar XQ2000/3516C, EPA Tier 2 and CARB certified units). With the revised configuration we will have approximately 2 MW of back up capacity available at site to complement the operating/production capacity of 15.5 MW allowed under our AEP.

Which rental generators are being moved?

RESPONSE: Due to noise complaints we are planning to relocate 3 of the remaining 5 rental units to a location approximately 45 metres northwest of their current location. This will allow the existing FD1 building to provide some sound attenuation during their operation. We are evaluating the feasibility of additional sound attenuation for the remaining rental units as part of our planning, but don't have an engineering assessment or cost estimate completed yet. See draft site sketch below for planned locations of units.



How far from their current location? A figure would be ideal. **RESPONSE: See above and attached.**

On a side note, I received your response in regards to the Faro Station Complaint Management System and will get back to you as soon as I can so we can finalize that plan.

Thanks and have a great day,
Liz

From: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Sent: February 9, 2023 9:04 AM
To: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Cc: Lisa Wiklund <lisa.wiklund@yec.yk.ca>
Subject: [EXT] RE: Faro Station Modifications

Hi Liz,

Thanks for reaching out.

As part of the presentation in Faro recently we also received several questions from a member of the public and are working on responses. I will try to get our responses over to you shortly for your consideration. If after reviewing, you have any follow up questions or concerns with our responses please feel free to reach out to me. Overall, I hope that what we share makes sense and is appropriate from your perspective, so I appreciate you connecting with me on this.

Regards,

Travis

Travis Ritchie
Manager - Environment, Assessment, & Licensing
Telephone: 867-393-5350 | Mobile: 867-333-0300

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SM-YEC-20141008MYEC-20141008

From: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>
Sent: February 9, 2023 8:08 AM
To: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Subject: Faro Station Modifications

Good Morning Travis,
Our minister received a message with some questions from a member of the public asking about proposed modifications to the Faro plant, as presented on January 24th by Paul Murchison and Ed Peake. The modifications described are as follows:

- Decommissioning FD1 – Mirrlees KV16 Generator
- Adding two new “permanent” generators, FD8 and FD9.
- Moving 3 “temporary” rental generators and infrastructure to a different

location in the facility.

- Removing 2 “temporary” rental generators.
- Possible addition of sound barriers around FD7 and/or two of the rentals
- YEC has stated that these modifications will change sound emissions from the FGS

I’d like to respond as soon as possible so I’m just looking for confirmation that these modifications are being planned and that we will receive notification prior to any work as per Part 2.5 of the Faro permit.

Thanks very much,
Liz

Elizabeth Barker
Environmental Protection Analyst
Environment | Standards & Approvals
T 867-667-5456 | Yukon.ca

From:	Travis Ritchie
To:	Emily.Sessford; Elizabeth.Barker
Cc:	Gary Jones; Attilla Heipel; Shannon Mallory (shannon.mallory@yec.yk.ca); Cody Hoy
Subject:	RE: 2023-038-Inspection-Report
Date:	May 31, 2023 4:54:00 PM
Attachments:	image001.png 20230510-Inspection-report-es.pdf 60-010-01 FARO (2022-2031) - signed.pdf image002.png image003.png image004.png image005.png image006.png

Hello Emily and Elizabeth,

Thank you for the inspection report (re. AEP 60-010-01 - Faro Generating Station).

Pursuant to the corrective/follow up actions outlined in the report, I offer the following information for your consideration:

YG Corrective Action 1:

Permittee is requested to follow-up regarding site changes, this includes decommissioning of generator FD-1, and the change in location of generators YM26-T1, YM25-T1, YM24-T1 and YM22-T1, as well as any other anticipated development or changes that may be occurring as required by permit.

YEC Response CA1:

Yukon Energy will provide a schedule and description of activities related to the decommissioning of FD1 for approval prior to removal of this source from the FGS property. We hope that since this source is being removed and will no longer be making emissions to air that the requisite approval can be reasonably provided under the existing YESAA Decision Document for the facility.

As regards any changes in the location of emissions sources, we ask for your consideration that such an approval is not required when such activities are occurring within the site boundary of a permitted thermal generating station. Part 2, Clause 5(b) of the current FGS air emissions permit appears to be an inadvertent holdover from previous versions of the authorization when all of Yukon Energy's thermal generating stations were authorized under a single (or blanket) air emissions permit. Yukon Energy has always had periodic operational requirements to move mobile generators from one facility to another and it was in this context, and that of a blanket permit, that necessitated the need for such a clause in past permits. An operational need for YEC to make minor adjustments to the location of generators within an individual facility boundary would not be reasonably expected to materially vary the character of the pollutant emissions from the site in a negative way and therefore we request that, in interpreting the permit, such activities not be subject to prior approval from the Regulator. YEC will certainly continue to request approval for changes in the location of sources *between* generating stations.

YG Corrective Action 2:

Permittee is requested to brief and make operators aware of the full complaint

management system in place.

YEC Response CA2:
The approved Complaint Management System for the FGS includes facility-based signage and website information for the public to phone, email, or submit online complaints to the Corporation. The receipt and management of such correspondence is made by YEC's External Affairs Department and is triaged as required to satisfy the requirements of the plan and interests of our stakeholders. The inspection findings have, however, made us more aware that as members of the community our facility operators may receive complaints via direct engagement with complainants and it would be useful for them to be able to relay details of how to effectively share such complaints with the Corporation (i.e., to verbally share the information about how to register a complaint via phone, email, or online).

As such, on or before June 30, 2023, Yukon Energy Environment Department staff will provide an orientation to relevant members of its Operations Team as to the scope and function of the Complaint Management System in place for the Faro Generating Station (FGS). We will also make such awareness training a mandatory part of orientations for new/temporary plant operators at the FGS.

If you have any follow up questions, comments, or concerns with these responses to the required corrective actions please let me know.

Thank you.

Regards,

Travis

yukon energy

Travis Ritchie
Director, Risk & Compliance
Telephone: 867-393-5350 | Mobile: 867-333-0300

SustainableElectricityCompany™

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SM-YEC-20141008

From: Emily.Sessford <Emily.Sessford@yukon.ca>
Sent: May 16, 2023 1:21 PM
To: Travis Ritchie <Travis.Ritchie@yec.yk.ca>
Cc: Elizabeth.Barker <Elizabeth.Barker@yukon.ca>; Gary Jones <Gary.Jones@yec.yk.ca>; Attilla Heipel <Attilla.Heipel@yec.yk.ca>
Subject: 2023-038-Inspection-Report

Good afternoon Travis,

Please find attached Inspection Report 2023-038 for Yukon Energy Corporation's Air Emissions Permit No: 60-010-01 at Faro. Please note the corrective actions and associated deadlines.

Sincerely,

Emily Sessford
Environmental Compliance Officer
Environment | Environmental Compliance & Inspections
T 867-667-5398 | C 867-332-2945 | Yukon.ca

REFERENCE: **Faro noise issues: Application PDF, p. 163**

QUOTE: The results of the noise survey indicated that the operational sound levels at various locations exceeded the nighttime permissible sound levels during operation of Faro diesel units. While the new diesel generators will have lower noise emissions than both the rentals and FD1, noise mitigation is included as part of the design and installation of the Faro diesel replacement project. (GRA PDF p. 163)

QUESTION:

a) According to YEC data provided by YEC at a meeting in Faro in January 2023, the current configuration at the the [sic] FGS exceeded nighttime permissible sound levels at all measured and modelled locations. At the meeting, YEC representatives presented new numbers that showed that permissible nighttime sound levels would still be exceeded at half of the locations after proposed diesel replacement and planned mitigation. Has YEC subsequently determined what will be changed or implemented to make the facility not exceed permissible noise levels?

b) Please provide the sound modelling report for the modifications to the Faro facility. This report was referenced by YEC in the January of 2023 meeting in Faro. I requested it from YEC on February 7 and was informed by YEC that “The full report is not yet available. The results of the sound modelling were shared ahead of the full report so they could be presented at the January meeting in Faro.” I requested the full report again in June and August, and still nothing. Is the full report finally available?

c) Given that the rentals are only used in colder temperatures, why is sound modelling done at 0c and 70% humidity in past reports and in the preliminary results provided?

d) Please provide a comparison of noise levels between the proposed diesel replacement generators and the rentals with both operating at 5MW output.

e) Please provide a comparison of the efficiencies of the proposed diesel replacement generators and the rentals at 5MW output. Fuel usage at 5MW, Fuel usage per MWh, and NO2 and other emissions compared.

ANSWER:

(a)

Yukon Energy has been conducting modelling to ascertain what effective sound attenuation treatments might be technically and economically feasible for the FGS to address the noise concerns raised by some residents of the Town of Faro. In addition to generator relocation and reorientation on the site in 2023 (with more planned in 2024), Yukon Energy is anticipating the installation of some sound attenuation devices (e.g., sound walls) in 2024 for key locations on the site, such as around external cooling system of the FD7 building. The 2023 and 2024 unit relocation and reorientations place the combustion air intakes and exhaust of the rentals in such a way that some noise is directed away from receptors as much as possible and the relocation of some units to the west side of the property allows for the existing substation and remaining FD1 building to provide some measure of sound attenuation.

Replacement of some of the existing FGS rental unit capacity with FD8 and FD9 will also provide a measure of sound reduction. The new units are materially quieter (~ 10 dBA) than the rental units or FD7, as outlined in the response to question (d), below.

With the relocation and reorientation of the rental units, the replacement of some rental capacity with FD8/9, and sound barrier installation at FD7 and potentially other locations on site, Yukon Energy is confident sound levels will be reduced. Yukon Energy's design target for operating sound levels at the nearest sensitive receptor in Faro is the stringent 43 dBA calculated permissible nighttime sound level. Recalling that Faro has extremely low ambient sound levels and comparing the target sound level to calculated permissible nighttime and daytime sound levels of 43 and 53 dBA, respectively, and pre-improvement sound levels of 50-55 dBA, Yukon Energy believes operating sound levels will be materially improved with the changes in progress at the FGS.

It is also worth noting that in cases where there is an existing facility, it is not always feasible to reduce the sound levels by 20 dBA as would be necessary to hit a strict 33 dBA target in Faro. In these cases, it is important to consider the change from current sound

levels. As noted in the paragraph above, based on both the modelling and measurements, sound levels as high as 50-55 dBA may exist from the current operations. A reduction to 43 dBA (the current design target) would be a significant improvement. Note that a 10 dBA change in sound level is commonly associated with sounding twice/half as loud.

(b)

The referenced sound modelling is being developed and used on an iterative basis to support preliminary and final engineering design of potential sound mitigation devices. This design work is still in progress. As such, a final report has not yet been completed. In the meantime, a summary memo has been prepared to support the response to this information request and is attached as NY-YEC-1-15(b) Attachment 1.

(c)

Air temperature and humidity do not make a significant difference in perceived sound levels. For example, at distances of 300-400 m, 0 degrees versus 20 degrees results in less than 1 dBA difference. Humidity makes even less of a difference, with approximately 0.1 dBA between 50% and 90% RH.

The largest meteorological differences are from wind speed and direction. Slight downwind conditions are assumed in the modelling for the Faro site.

(d)

The sound power levels generated by the rental units installed at the FGS is approximately 117 dBA. The sound power levels generated by FD7 is approximately 119 dBA. The sound power levels of the new FD8 and FD9 units is approximately 107 dBA. Note that a 10 dBA change is described by a human listener as twice as loud.

(e)

Please see response to NY-YEC-1-13(f) and NY-YEC-1-13(d).

SLR Consulting (Canada) Ltd.
6940 Roper Road NW, Edmonton, AB T6B 3H9

November 23, 2023

Attention: Travis Ritchie
Yukon Energy Corporation
#2 Miles Canyon R.
Box 5920, Whitehorse, YT Y1A 6S7

SLR Project No.: 201.V38355.00000

RE: Faro Generating Station – Noise Modelling Results MEMO

SLR Consulting (Canada) Ltd. (SLR) has completed an acoustical modelling assessment of the proposed changes to Yukon Energy's Faro Generating Station (the Facility). The current facility has 9 diesel-fired generating units, one of which is no longer in service. Yukon Energy is proposing the addition of two new units and the relocation of some of the rental units within the site footprint.

- FD1 Mirrless KV16 2.4 MW genset located within a permanent building – Retired
- FD7 Caterpillar 3612 2.8 MW genset located within a permanent building
- YM20-YM26 Caterpillar 3516 1.8 MW (each) trailer mounted gensets, "Rental Units"

Proposed Units:

- FD8 & FD9 Caterpillar C175-16 2.6 MW gensets (each) located within modularized acoustic enclosures.

The nighttime noise target for this project is 43 dBA at surrounding residential receptors. Further discussion on the noise target and community receptor locations are described in SLR's prior Noise Survey Report[1].

Operational Scenarios

This assessment has evaluated the following operational scenarios. A site plan showing the unit locations is included below in Figure 1. Note the rental units shown are in the new locations. Historically, 7 rental units were aligned along the south side of the property, adjacent to the 2 south rental units shown in the sketch. In addition, sketches showing the layout and dimensions of the sound barriers are attached.

0 Historical Operations

a) 7 rental units (historical locations) + FD7 (no sound barrier)

1 2023/2024 Winter Scenarios

a) 7 rental units + FD7 (no sound barrier)

b) 7 rental units + FD7 (with sound barrier)

[1] 201.38355.00000 Yukon Energy Faro Generating Station Noise Survey Report - FINAL 2022-10-05.pdf

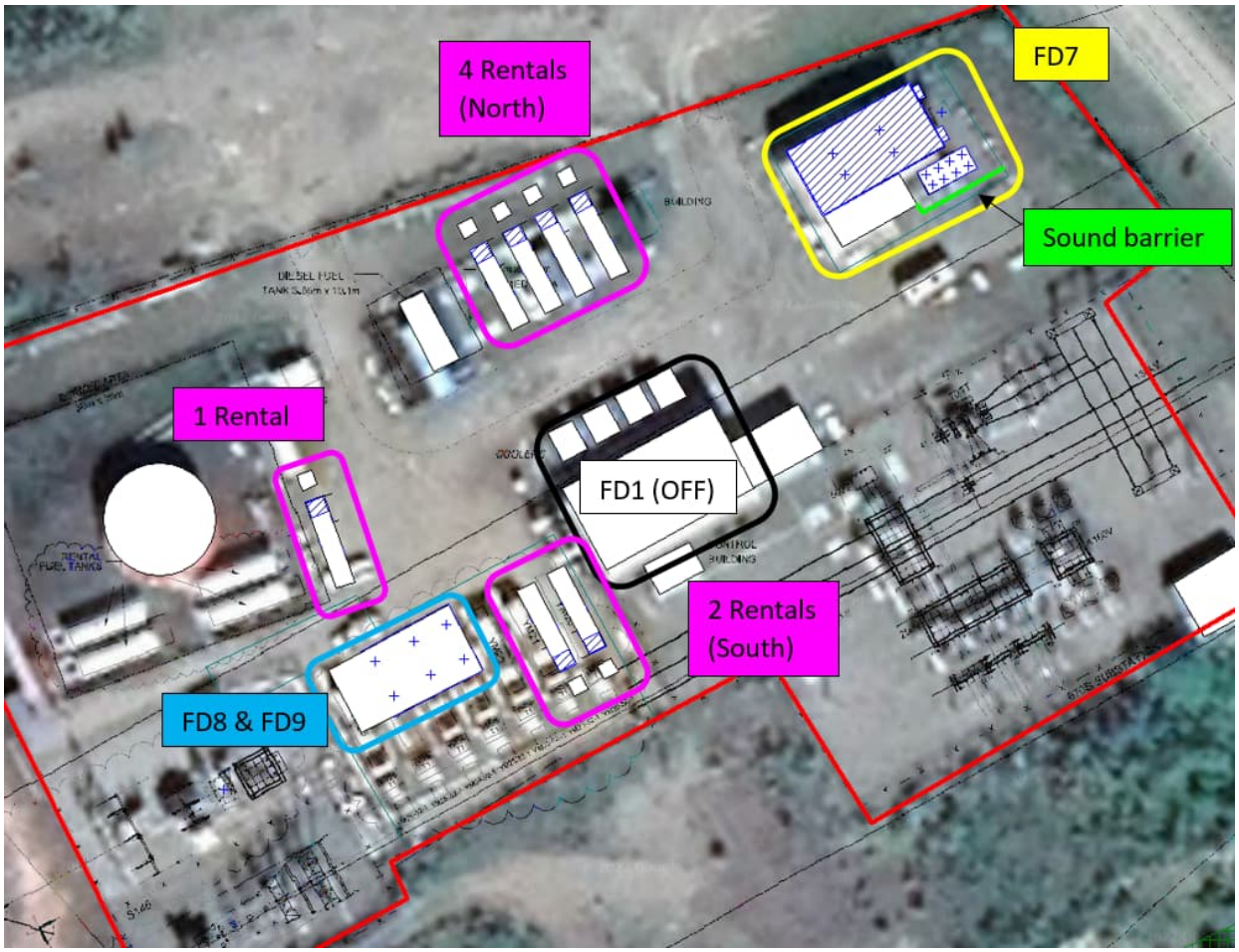
2 After 2023/2024 Winter Scenarios

a) 5 rental units (4 North, 1 South) + FD7 (with sound barrier) + FD8, FD9

b) 4 rental units (North) + FD7 (with sound barrier) + FD8, FD9

c) 6 rental units (4 North, 2 South) + FD8, FD9

Figure 1 Site layout



Sound Propagation Modelling

A three-dimensional computer sound model was constructed using CadnaA, version 2023, an environmental sound propagation program developed by DataKustik GmbH. The ISO 9613-2 calculation method for outdoor sound propagation from industrial facilities was used and accounts for geometric spreading, ground attenuation, atmospheric absorption, barrier attenuation, and reflection from surfaces.

Predicted sound levels were calculated for a temperature of 0°C and a relative humidity of 70%. ISO 9613-2 standard meteorological conditions conservatively assume each receptor is downwind from every sound source. Downwind conditions produce downward refraction of air-borne sound, resulting in enhanced sound propagation between the source and receptor.

The terrain was modeled using elevation data from Natural Resources Canada with a 1 m height resolution between contour lines.

The default ground factor was set to G = 1 across the study area to represent acoustically absorptive ground, simulating snow-covered winter conditions. The site area was assigned a ground factor of G = 0.3. Foliage was included in the modelling at a height of 11m for the forested areas between the generating station and the receptors.

Sound levels were calculated at a height of 1.5 m.

Source Sound Power Levels

Sound power levels of the existing genset units were determined from on-site sound level measurements conducted on March 29-30, 2022. Sound power levels of the proposed FD8 & FD9 units were determined from manufacturer's data and information provided by Yukon Energy. Overall sound power levels per unit are shown in Table 1.

Table 1: Facility Sound Power Levels

Equipment	Octave Band Sound Level, dB									dBA
	31.5 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1 kHz	2 kHz	4 kHz	8 kHz	
YM Rental Unit (each)	115	116	118	115	113	112	110	107	108	117
FD7	113	117	117	116	116	114	111	108	103	119
FD8 & FD9 (each)	116	117	112	101	96	95	91	92	107	107

Modelling Results

Modelled sound levels at the surrounding community receptors are shown below in Table 2. All scenarios show a reduction in the sound levels in comparison with the historical operations. The critical receptor is R4 which represents the residences along Kitza Ave. This location is elevated and has direct line of sight to the Facility. Nevertheless, a reduction of 3.6 dBA from the historical scenario (0a) to the future scenario 2c) is achieved.

Table 2: Modelling Results

Operational Scenario	Sound Pressure level (dBA)					
	R2 130 Dawson Dr.	R3 RCMP Office	R4 146 Kitza Ave.	R5 356 Campbell St.	R6 504 Douglas Dr.	R7 502 Ladue Dr.
0a) 7 rental units (old locations) + FD7 (no sound barrier)	50.3	55.5	51.4	44.9	42.0	43.7
1a) 7 rental units + FD7 (no sound barrier)	48.4	53.9	50.2	43.5	42.1	43.7
1b) 7 rental units + FD7 (with sound barrier)	47.9	53.3	49.6	42.3	41.9	43.6
2a) 5 rental units (4 North, 1 South) + FD7 (with sound barrier) + FD8, FD9	46.0	51.5	47.5	40.3	41.0	42.5

Operational Scenario	Sound Pressure level (dBA)					
	R2 130 Dawson Dr.	**R3 RCMP Office**	**R4 146 Kitza Ave.**	**R5 356 Campbell St.**	**R6 504 Douglas Dr.**	**R7 502 Ladue Dr.**
2b) 4 rental units (North) + FD7 (with sound barrier) + FD8, FD9	44.3	49.4	46.0	38.4	39.8	41.5
2c) 6 rental units (4 North, 2 South) + FD8, FD9	46.6	51.5	47.8	41.0	40.8	42.3

Statement of Limitations

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Closure

Regards,

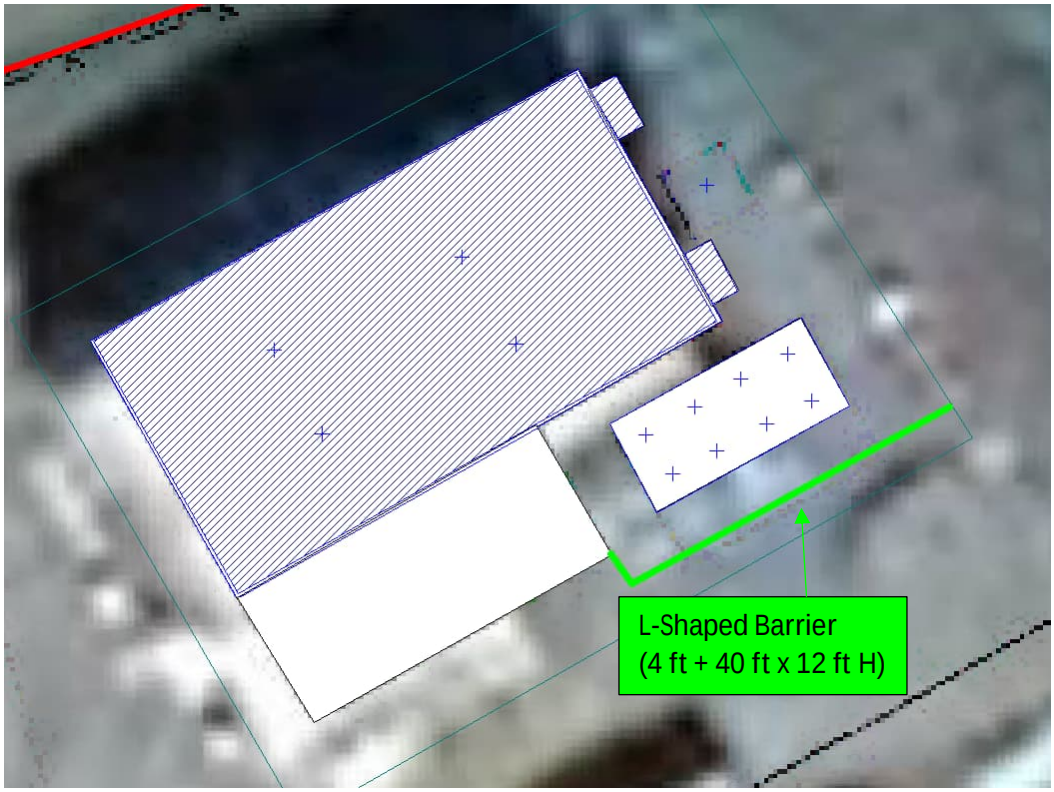
SLR Consulting (Canada) Ltd.

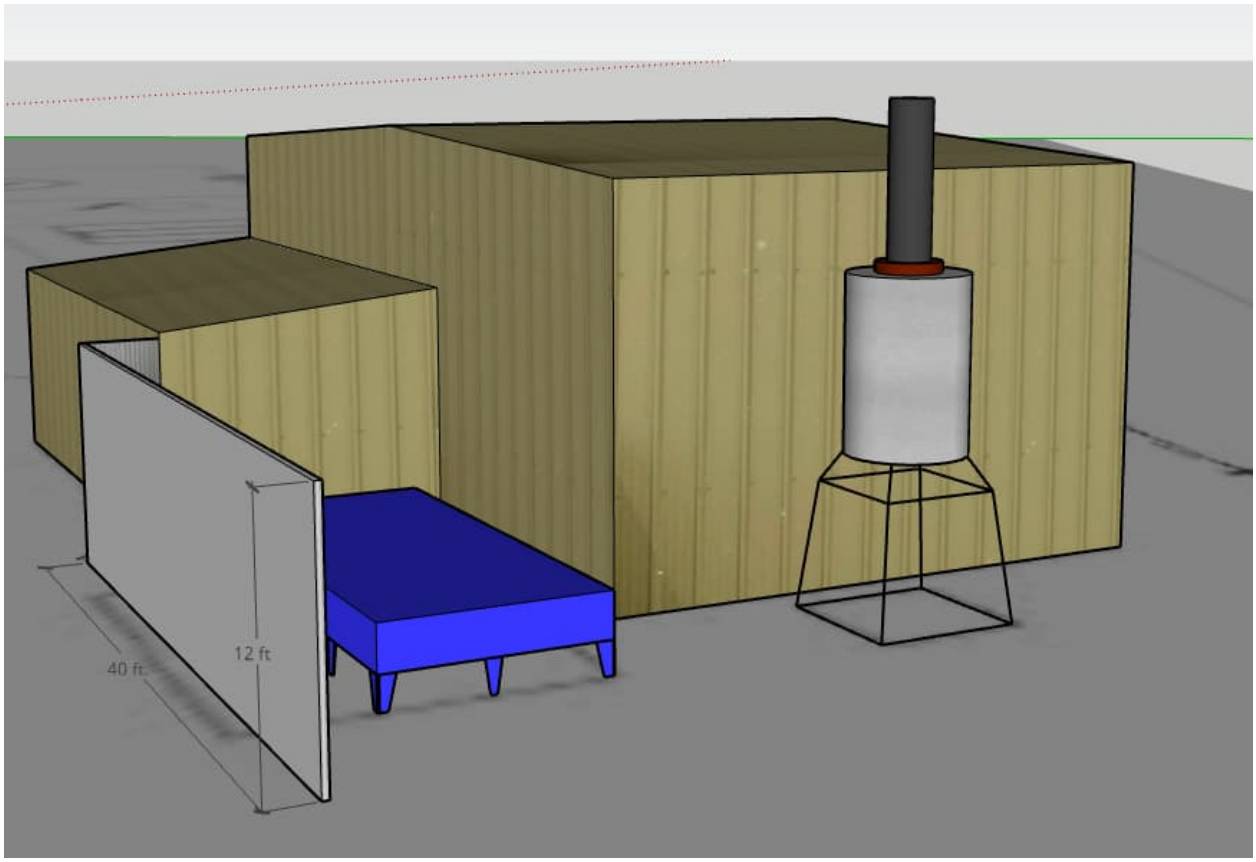
Arthur (Art) Küpper, P.Eng.
Principal Engineer & Environmental Team Lead -
Acoustics & Vibration

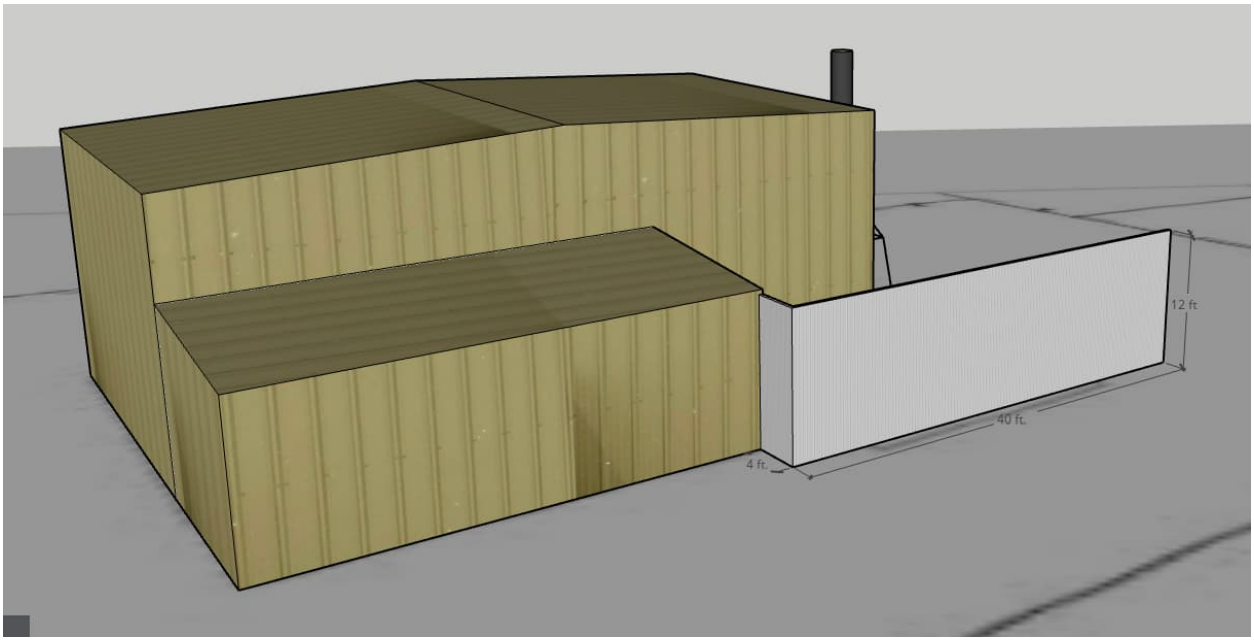
Attachments Sound Barrier Sketches

cc Emmanuel Ogemuno

Acoustical Barrier Sketches – FD7






12 ft.
40 ft.
4 ft.

REFERENCE: Tier 2 Diesels

QUESTION:

a) Other than the ever expanding rental diesel fleet, will YEC be installing any more dirty Tier 2 diesels?

b) My understanding is that Tier 2 is considered an obsolete standard and that Tier 2 units can no longer be imported to Canada. Is this correct? What year did this happen?

ANSWER:

(a)

Tier 4 is the strictest current standard, so the best available technology, and what YEC has committed to install for diesel generation going forward.

(b)

Tier 2 engines subject to the Off-Road Compression-Ignition Engine Emission Regulations, of the Canadian Environmental Protection Act (1999) were non-compliant as of January 1, 2018. We understand non-compliant engines are no longer importable into Canada. A number of diesel engines are exempt from these regulations including installed engines, and diesel engines generating electricity in small remote communities.

REFERENCE: **Ref: Application p. 5.1A-13, PDF p. 166)**

ISSUE: Mayo rental diesel:

QUOTE: To provide sufficient dependable capacity for the YIS during the W2023, 20 rental diesel units (36 MW) are required to address the shortfall in required dependable capacity that the YIS permanent facilities can provide. This is an increase of 5 required diesel rental units compared with the prior winter. (GRA p. 5.1A-13, PDF p. 166) and
Ref: Mayo has been selected as the location for the five added diesel rentals needed for 2023. (GRA p. 5.1A-13, PDF p. 166)

QUESTION:

Taking this together, YEC is counting on running each of the 20 rentals at full capacity of 1.8 MW each. (20 x 1.8 MW =36 MW). So 9 MW is attributable to the five added diesel units in Mayo.

a) YESAB 2023-0090 for the Mayo rental diesels was for 4.9 MW. How does YEC propose to meet N-1 planning criteria with 4.9 MW from the Mayo rentals instead of 9 MW?

b) In the YESAB process, YEC declared two of the five generators to be “backups” or spares. Where is this shown in the GRA?

c) What is YEC’s of understanding of “dependable capacity” and the YESAB and permitting processes? Does capacity have to be assessed and permitted for YEC to consider it as “dependable capacity” or N-1 dependable capacity?

d) What is the dependable capacity of the Mayo rental diesels in an N-1 emergency?

e) Why did YEC apply to YESAB for a 4.9 MW limit for the Mayo rental diesels while claiming 9 MW of dependable capacity to the Board?

ANSWER:

(a) to (e)

As provided in response to NY-YEC-1-2 Attachment 1, the dependable capacity forecast for the 2024/25 winter in Mayo from rental diesels is 7.2 MW [four units, excluding one spare unit] to close the N-1 dependable capacity shortfall.

In the referenced Yukon Environmental and Socio-economic Assessment Board (YESAB) submission, Project Assessment 2023.0090:

- Proposed installation and commissioning of up to five rental diesel generators at 1.8 MW each [total of 9 MW].

- YEC clarified that two of the up to five units installed at site are intended to be available as back-up in case of emergencies [i.e., they are not intended to be used during normal operating conditions]. YEC did not identify the two additional units as "spares" in the YESAB submission.

- The submission proposed up to a maximum operating capacity of 4.9 MW, during peak demand (winter) and during emergencies. In YEC's June 29, 2023 IR responses to the YESAB, YEC clarified that it was "seeking approval from the Yukon Government to operate up to 4.9 MW of fossil fuel-fired electrical generating equipment at any one time at the Project site", i.e., not only under N-1 emergencies but any time, including during winter peak hours.

- YEC also noted that the project will provide a redundant source of electricity supply close to the community of Mayo in the event of a regional transmission line or local hydro electric generation failure.

Consistent with the YESAB proposal, the 2023/24 GRA includes five rental units in Mayo, including one spare unit based on forecast peak demand and available dependable capacity for 2023/24 and 2024/25 winter. YEC will operate up to 4.9 MW capacity at any one time, including during winter peak hours while the remaining capacity is available during emergencies such as N-1 events.

As indicated in the Application, the Air Emissions permit limits normal operations to a certain capacity without limiting actual installed capacity or capacity operation during an N-1 event to protect public health and safety. Under Section 49 of the Yukon Environmental and Socio-economic Assessment Act, YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety which the YUB agreed to in Order 2022-03 (para 110) stating that "… N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in interest of public welfare, health or safety."

While YEC understand there are provisions in YESAA to preclude the need for an assessment in the case of an emergency, there are no such provisions in the Environment Act or Air Emissions Regulations. As such, Yukon Energy would communicate with the Authority Having Jurisdiction for air emissions (Yukon Government – Environment Department) in the case of a requirement or occasion where any particular generating station anticipated exceeding or did in fact exceed its permitted operating capacity. Yukon Energy would address any requirements of the AHJ under such circumstances to the best of its ability.

REFERENCE: **Ref: Application Section 5.1A-1, p. 5.1A-9, PDF p. 162**

ISSUE: Faro Thermal Replacement Project

QUOTE: The YESAA assessment of the Faro project location was completed in early Q2 2022 and the Air Emissions permit to operate beyond 10.6 MW was issued to YEC. The Air Emissions permit limits normal operations to a certain capacity without limiting actual installed capacity or capacity operation during an N-1 event to protect public health and safety[10].

And

[10] Under Section 49 of the Yukon Environmental and Socio-economic Assessment Act, YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety. The Board found in Appendix A to Order 2022-03 (para 110) "…that N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in interest of public welfare, health or safety."

(GRA p. 5.1A-9, PDF p.162)

QUESTION:

a) While section 49(1) of YESAA states the "no assessment is required" in response to an emergency, the YESAB assessment is only part of the authorization to run generators. Has this "unlimited capacity" idea been confirmed with the Department of Environment?

b) What steps must be taken before capacity that has not been permitted or assessed can be used in an N-1 event?

c) The permitted capacity of the FGS is 15.5 MW, and YEC is claiming 20.6 MW dependable N-1 capacity for 2024-25. Is this correct? (GRA PDF p.163)

ANSWER:

(a)

At some generating stations more generating capacity exists than is permitted by the air emissions permit to be operated. This additional capacity is retained for backup purposes. Yukon Energy would notify the Regulator (YG Environment) of any requirement in an emergency to operate capacity available at a generating station beyond the permitted production capacity. As previously described and reviewed in "c" below, this arrangement is consistent with existing regulations and has not needed confirmation with the Department of Environment.

(b)

Yukon Energy would notify the Regulator of the emergency and the permitted production capacity exceedance.

(c)

The permitted production capacity for the FGS is 15.5 MW.

As provided in response to NY-YUB-1-2 Attachment 1, the total dependable capacity forecast for the 2024/25 winter in Faro is 20.6 MW – this includes 8 MW permanent dependable diesel capacity [including the new 5 MW diesel replacement] plus 12.6 MW temporary diesel rentals to close the N-1 dependable capacity shortfall.

As indicated in the Application, the Air Emissions permit limits normal operations to a certain capacity without limiting actual installed capacity or capacity operation during an N-1 event to protect public health and safety. Under Section 49 of the Yukon Environmental and Socio-economic Assessment Act, YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety which the YUB agreed to in Order 2022-03 (para 110) stating that "… N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in interest of public welfare, health or safety."

While YEC understand there are provisions in YESAA to preclude the need for an assessment in the case of an emergency, there are no such provisions in the Environment

Act or Air Emissions Regulations. As such, Yukon Energy would communicate with the Authority Having Jurisdiction for air emissions (Yukon Government – Environment Department) in the case of an emergency requirement or occasion where any particular generating station anticipated exceeding or did in fact exceed its permitted operating capacity. Yukon Energy would address any requirements of the AHJ under such circumstances to the best of its ability.

ISSUE: **Diesel Rental Business Case, Rental costs:**

QUESTION:

a) Are the per unit rental costs of the 22 rentals (including spares) the same across locations?

b) Are operational costs and fuel costs the same across the rentals? If not, please explain the differences.

c) Are all 22 of the rentals on the same contract with the supplier? Please provide contract(s) or agreement(s) for all years of rental diesel.

d) How has the per-unit rental cost changed over the years of YEC rental diesel? Please provide a table with a breakdown of total cost, per unit cost and number of units for each year that YEC has rented diesel generators. Please also include actual or expected cost for 2024-25.

e) Is there a competitive bidding for the supply of rental diesel, or does the same supplier always get the contract? Please provide rationalizations for whatever approach is taken, and describe the process including time of year for each part.

ANSWER:

(a) to (d)

No, the rental costs differ by location. Please see the response to YUB-YEC-1-1. The fuel costs also differ by location. Please see Application page 3-5 for the details of diesel fuel prices by location.

Please see the response to YUB-YEC-1-1 for available information on rental agreements and rental costs.

(e)

Please see the response to YUB-YEC-1-24 (f).

ISSUE: **Diesel Rental Business Case, Rental costs:**

QUESTION:

a) This model of rental generator is relatively common, and examples can often be found for sale. What is the typical cost of purchase for rental diesel units of this type on the open market? Provide examples

b) What is the cost of purchase for rental diesel units from the current rental supplier? Has YEC made any inquiries? Please provide written quotes received

ANSWER:

(a)

A portable 1825 KW generator with required protective relays, remote control features and ability to run reliably in the Yukon's harsh winter is uncommon. YEC currently has the entire fleet of such rentals from Finning for the 2023/2024 winter and we are currently looking for alternative vendors through an RFQF process for future years.

(b)

Please see below table of budgetary pricing received from various vendors. Note that YEC rents a full generation package including the generator, step up transformer and fuel tanks as well as other secondary cabling. Additionally, YEC does not have the resources to maintain the quantity of rental generators and the supplier (Finning) is contracted to perform preventative maintenance, repairs and commissioning activities. Purchasing diesels would result in additional O&M costs including staff, property tax and insurance.

Diesel Generator Trailer Purchase Price		
Model Name	Name	Caterpillar XQ2000
Power Rate	kW	1,800
Genset Rental Price	$/unit	1,692,350
Transformers (2500kVA)	$/unit	185,831
Spillberms	$/unit	7,633
Fuel Tank @ 75,000 L	$/unit	107,770
Fuel Tank @ 25,000 L	$/unit	107,770
LNG Generator Trailer Purchase Price		
Model Name	Name	Caterpillar XGC190
Power Rate	kW	1,900
Genset Rental Price	$/unit	1,991,250
Transformers (2500kVA)	$/unit	185,831
LNG Fuel Tank (134,000 L)	$/unit	603,000
Regasification Facility	$/unit	1,000,000

REFERENCE/ QUOTE:

Ref: During the review of YEC's 2021 GRA, YEC explained why trading diesel engines [i.e., purchasing diesel rental units and sale later when it is not needed] is not considered to be a feasible option for YEC.[1] (GRA PDF p.91)

[1] See September 29, 2021 hearing transcript, line 16 at page 460 to line 21 at page 463.

and

In the referenced part of the transcript, Andrew Hall states "If we were to look at an option to purchase and then sell again in the future, we have to look at, firstly, you know, what certainty we have around those overall economics."

ISSUE: Diesel Rental Business Case, Rationalizations

QUESTION:

a) How thoroughly Has YEC looked at the economics? Please provide data on purchase and resale options. How is claiming that one has to analyze an option a strike against that option?
He goes on to say "In terms of practicality, you know, I'll draw folks attention to Figure 20 again in the 10-year renewable plan, and I'll just get a reference there."
Figure 20 shows a reduction in rental diesel, as Atlin and BESS come online in 2024, and elimination of rental diesel when moon lake Moon Lake is online in 2028.

b) Mr. Hall points to a graph showing that rentals will be reduced in 2024 and eliminated by 2028. Is there any validity for YEC to be citing this in a business case in 2023, given that things are clearly not playing out that way?

c) Are there any lessons learned from the failure to make meaningful progress with renewables as evidenced by the referenced graph?

d) Much of the reasoning of the business case seems to hinge on the rentals being temporary and disappearing soon. This does not seem to be happening. Are rental diesels they only/best option if they are still needed 10 years from now? 15 years? 20? Please discuss and provide any supporting data concerning longer term rental diesel.

He also states “So this whole idea of getting into the business of trading pretty much on an annual basis diesel engines, I mean, that's not our business, and I wouldn't be comfortable with us getting into that line of work.”

e) How is “temporary rental diesel” any more YEC’s traditional business or “line of work” than the purchase and operation of generation equipment? Mr. Hall’s mention of “trading pretty much on an annual basis” rings hollow given that so far, there would have been no need to sell any units.

f) Mr. Hall does not consider the option of the combination some purchase and some rental. This also seems to have been ignored in the Business Case. Please provide any research done on a hybrid approach.

ANSWER:

(a),(b) and (c)

The referenced transcript from the 2021 GRA provided comments in the context of the decision to not proceed with a 20 MW diesel plant project and adoption of YEC’s 10-Year Renewable Electricity Plan with Moon Lake planned to be on-line in 2028. In the context of that plan, an option of spending material capital to install new diesels sufficient to remove a need for rental diesels prior to 2028 raised the issues noted by Mr. Hall, including:

- Rented diesels were an absolute requirement, i.e., the only feasible option to meet requirements, prior to the time needed for planning, permitting, acquisition and installation of new diesels. Rented diesels also deferred requirements for YEC to secure additional capital funding needed for any new diesel option.

- A material portion of diesel rentals was planned to be removed within a few years, through Atlin, BESS and diesel replacement projects as well as DSM planned to come on-line by 2024. Purchase of new versus rental diesels for this initial brief period would undermine the feasibility of these other projects absent clear proof (which YEC could not see securing) that purchase-resale for this brief initial period would be less expensive than rentals.

- Looking beyond 2024, the possibility also existed for install of new diesels to undermine the feasibility of the proposed Moon Lake Pumped Storage renewable project if resale of the diesels proved in reality (i.e., at the time of the decision to proceed or not with Moon Lake Pumped Storage) to yield inadequate cost recoveries. Absent clear evidence that rentals were materially more costly than the new diesel/ resale option (which YEC could not see securing) for the somewhat longer period to 2028, YEC's plan also retained diesel rentals during this period.

- Based on the above considerations, and limits on YEC resources, YEC did not consider it prudent to invest material effort to look at the economics of the purchase/ resale option for this time period.

As reviewed in the 2023/24 YEC GRA, development of an Electricity Supply Plan is underway to take account of ongoing changes, including delays expected in development of the Atlin Expansion Project EPA and the Moon Lake Pumped Storage Project. At the same time, Yukon Energy will continue examining the relative costs and risks for new versus rental diesel options taking into account options to sell purchased new diesels when dependable renewable capacity is added to the grid.

Lessons learned since the 2021 GRA and adoption of the 10-Year Renewable Electricity Plan include risks for delays and material cost escalations in new generation and energy storage resource projects as evidenced in recent projects like the Atlin Hydro Expansion project, BESS and Thermal Replacement Project. The Energy Supply Plan will utilize these learnings in its assessment of current options and their expected benefits, risks and costs.

(d), (e) and (f)

As reviewed in response to (a) to (c) above, the business case for rental diesels focused at the outset on this being the only available option for YEC to address dependable capacity shortfalls in the earlier GRA test years, and focused going forward on the near-term planning for development of non-rental diesel options that would greatly reduce rentals by 2024 and remove the need for material rental diesel capacity by 2028. Trading and purchase/ resale options were discussed in the 2021 GRA proceeding only in this context. Rental diesels were never proposed by YEC as a longer-term resource plan.

All relevant options will continue to be examined and assessed for future years in the current resource planning update. These update assessments, however, do not affect evaluation of the current 2023/24 GRA resource costs proposed to be included in the 2023-2024 test years.

REFERENCE: **Ref: Application p. 3.1-4, pdf p. 92**

ISSUE: Diesel Rental Business Case, longer term lease vs short term rental and prudence:

QUOTE: With respect to the further alternative of a longer-term lease of diesel rental units, instead of short-term rentals during the winter months of the test years, YEC has concluded that this is not a viable or prudent option. (GRA p. 3.1-4, PDF p. 92)
and from the Atilin EPA Submission:
Referencing a possible need for up to 35 rental units, YEC has noted that "In additional [sic] to the challenges finding this number of rental diesels, YEC would also face location and connection issues to safely connect diesel rental units to YIS." (YEC Atlin EPA Submission pdf p.23)

QUESTION:

a) What are the costs and terms available of a longer term lease? For one year? For 3 years? For 5 Years or more? Please provide quotes from the supplier.

b) When in the yearly cycle does YEC inform the supplier how many rental are needed?

c) Having only short term leases, and given that YEC has noted potential challenges in finding rentals, is there a possibility that an insufficient number of generators will be available in a given year?

d) Does YEC have any alternatives or a backup plan if the desired number of short term rentals are not available any given year?

e) Is it prudent to have unreliable and possibly unavailable rental diesels taking on an increasingly large role in Yukon's energy supply?

ANSWER:

(a)

Yukon Energy has contracts totaling $7.1 million dollars for the rental and servicing of 22 units in 2023/2024. The supplier provided a quote for a one-year extension (the 2024/2025 season) with a 4% increase from 2023/2024. The supplier did not provide quotes for longer than two-years.

YEC is currently running a procurement process to set up a longer- term contract. While the length of the term is not yet finalized, YEC expects the term to be at least five years. The procurement will be run as a two-staged process that screens in potential suppliers based on their capacity to meet our technical and service standards. The second phase of the process will be primarily focused on pricing and schedule. One challenge with longer term contracts is determining the number of units required in future years as that can vary based on future demand and completion of other capital projects.

(b)

Typically, YEC informs the supplier how many rental units are required around March or April. At this juncture, YEC has more confidence with respect to forecast demand requirements, project schedules and can make operational and finance decisions with respect to whether units are returned, kept on stand-down, or whether more units will be required. Delaying the decision as long as possible results in the most accurate forecasts. In the Atlin EPA, section 4.3 recognizes the need to finalize rental commitments by June for the following winter season.

(c)

Yes, it is theoretically possible that an insufficient number of generators will be available in a given year. To reduce the risk of this occurring, YEC has built a strong relationship with the existing supplier and is continually in discussions with the supplier throughout the process until the contract is finalized. The decision making that occurs in March or April has provided the existing supplier sufficient time to ensure it has capacity to fulfill the contract. To further reduce this risk going forward, YEC is investigating a longer-term contract as noted in (a) above.

(d)

In the unlikely event that the existing supplier was unable to completely fulfill YEC's requirements, YEC would look at other options including rentals from other suppliers, use of generators from industrial customers or purchase of other forms of generation.

(e)

It is prudent for the 2023 and 2024 Application test years. Looking beyond the test years, the decision to rent diesels will be based on a number of factors that are continually changing. As a result, this must be continually reassessed with options available. YEC is currently reviewing and updating its short- and long-term plans for capacity resources (please see response to NY-YEC-1-11 and YUB-YEC-1-1).

More permanent solutions often take a longer time to implement, so even after a decision is made to move away from rentals, rentals may be required during the interim period. An example of this is the expanded Thermal Replacement project where more generation is being added, but these projects will not be completed until 2024-2025.

REFERENCE: **Ref: Application p. 3.1-7 , pdf p. 95**

QUOTE: In contrast, using new purchase costs for the 5 MW of Faro units in service in 2024 at $3.66 million/MW, the LCOC for new units sold in the 11th year after commissioning can only compete with the rental option at unrealistically high sales prices. For example, an unrealistic 10-year sales price equal to 75% of original cost (reflecting the remaining three-quarters of the original expected life) yields an LCOC for the purchase option of $278/kW-yr which remains much higher than the LCOC for the rental option in these specific circumstances. (GRA PDF p.91 [sic]) This appears to suggest that the option of selling the new diesels purchased as part of diesel replacement would not be prudent

QUESTION:

a) Why is YEC considering or analyzing selling the new “permanent” diesels?

b) How does showing that selling the permanent diesels is not prudent support the Diesel Rental Business Case?

ANSWER:

(a)

YEC evaluated options to purchase thermal units and then sell them at a later date when dependable renewable projects come online. In such options, the sale of the ‘permanent’ units is needed to recover undepreciated capital costs as the capacity is no longer needed. This comparison was done to make sure all options were evaluated and compared to continuing to use rental units to bridge the dependable capacity shortfall into the future.

Note that YEC is not considering selling the units installed as part of the ongoing Diesel replacement project. YEC has not proceeded to seek quotes from any suppliers for this option.

(b)

Assessment of the “own/resell” option is only done to confirm that this specific option is not preferable to rentals in situations where a planned future event (e.g., new dependable renewable capacity, reduction in forecast peak demand, or other forecast developments) is forecast to reduce the dependable capacity shortfall.

Typically, thermal units are expected to have a 40-year life span. If the sale of the units is not considered, the business plan would not reflect the residual value of the purchased units.

ISSUE: Our Diesel Future?

QUESTION:

a) Why have recent GRAs been about adding more “temporary rental diesel”, while minimizing or ignoring the clearly needed focus on longer term solutions.

b) What failures in the planning process have brought us to an unstable, ever expanding temporary quick fix cycle?

c) Does YEC have any guidance for a much needed intervention? A plan for progress? A rehab plan to get off of the growing rental diesel addiction? Why isn’t this happening?

ANSWER:

(a),(b) and (c)

GRAs deal with test year revenue requirement forecasts for assets in-service that are used and useful as well other costs applicable in the specific test years under review. Long-term resource planning will be discussed, but potential resource options for implementation beyond the test years are not the focus for a GRA.

In this context, recent GRAs have been addressing actual generation and other resource options forecast to be in service after the decision not to proceed with a 20 MW diesel project option, adoption of the 10-Year Renewable Electricity Plan, and actual implementation outcomes for near-term projects planned to be implemented for the relevant test years. The 10-Year Renewable Electricity Plan, however, focused on longer-term solutions that could greatly reduce rentals by 2024 and remove the need for material rental diesel capacity by 2028.

As reviewed in the 2023/24 YEC GRA, Yukon Energy is developing an Electricity Supply Plan to take account of ongoing changes, including delays expected in development of the Atlin Expansion Project EPA and the Moon Lake Pumped Storage Project. At the same, Yukon Energy will continue to examine relative costs and risks for new versus rental diesel options taking into account options to sell purchased new diesels when dependable renewable capacity is added to the grid.

QUESTION:

a) There seem to be very few incentives for customer participation in DSM programs. Does YEC really expect many customers to give up control of their heat or water heaters or EV charging often in exchange for little more than a free device that allows the utilities to take control?

b) How much of a peak reduction does YEC expect to get from the current DSM programs in future years?

ANSWER:

(a)

The Residential Demand Response Program is the only program with a Participant Cost Test (PCT) result below 1.0, suggesting participation incentives may impact program uptake. However, strong public interest in the Residential Demand Response Pilot (publicly referred to as the "Peak Smart pilot"), which offered similar benefits to participants and was ultimately oversubscribed, suggests that the incentives provided through Residential Demand Response Program poses a low risk to program success. The program's preliminary cost-effectiveness test results suggest that additional participation incentives could be offered without severely impacting the program's cost-effectiveness or equity, should additional incentives be deemed necessary by low program uptake. Program uptake will be monitored regularly to assess whether additional incentives are necessary to meet the program's participation targets of at least 400 homes.

All other programs pass the PCT test, indicating that the incentives offered will be sufficient to meet participation targets. Program uptake will be monitored, with incentives adjusted as appropriate to support program uptake while maintaining program cost-effectiveness and equity.

(b)

YEC has a target of 7 MW of dependable capacity from its DSM programs by 2030, including all proposed programs.

ISSUE: **Time of Use rates: and customer motivations:**
There is no mention of TOU rates in this YEC GRA. TOU has proven to motivate customers towards DSM and peak shifting strategies. This seems important given YEC's peak load and N-1 issues. AMI and TOU are mentioned in the AEY GRA, but AEY is less affected by peak load, peak load not actually being mentioned in their GRA.

QUESTION:

a) Please explain how TOU rates could help (or not help) address load issues.

b) When will we see YEC push towards TOU billing? If not, why not?

c) Does YEC foresee a joint AEY/YEC application / proceeding towards TOU?

d) Does YEC have any other programs besides DSM described in the GRA that would help address peak load?

e) What is the best way to encourage customers to use electricity more efficiently?

f) What is the best way to encourage customers to reduce usage at peak times?

ANSWER:

(a)

TOU rates, also referred to as variable rates, are a rate structure by which customers are offered different rates for electricity usage at different times of the day and perhaps also different seasons of the year. Offering lower rates during typical periods of lower demand, and higher rates during typical periods of high demand, provides customers with financial motivation to shift their electricity consumption to periods of lower demand. This tends to shift demand away from typical periods of peak demand, such as in the morning and evening on cold winter days, reducing peak demand.

(b) and (c)

Utility meters with Advanced Metering Infrastructure (AMI) capabilities are required to implement variable rate structures, such as TOU rates. Most meters in the Yukon do not currently have this capability, presenting a technical barrier to TOU rates.

AEY in its 2013-15 GRA proposed to convert conventional electronic and mechanical meters to automated meter reading (AMR) technology. The project included installing two-way automatic communication system (TWACS) substation equipment at Whitehorse Substation S150 and McIntyre Substation S170 and to convert all meters in the Whitehorse area, Marsh Lake, Carcross, Tagish and Teslin communities to AMR technology.

AEY noted that it did not invest the significant time, effort and dollars to study TOU rates as there was no benefit to ratepayers and no directive to move to TOU rates stating that "…preliminary estimates to implement a new technology fully capable of time of use rates and integrate it with the billing system would be significantly more expensive than the proposed AMR project, mitigating any cost benefits of time of use rates to ratepayers."

The YUB in its Order 2014-06, Appendix A section 10.8.1.1 stated the following:

> "The Board has concerns with the business case because the cross-over of the benefits is still nine years away which puts the economic benefits of the business case at risk. The Board agrees with UCG's submission that the payback period is too long for such a small customer base, especially when one considers the rate at which technology changes. Furthermore, the Board shares the concerns of CW that until there is conclusive evidence either way regarding the imposition of TOU billing, proceeding with AMR at this time may result in additional risk to customers. Due to these concerns the Board is not prepared to accept the project and directs YECL to remove this project and its costs from rate base. The Board further directs YECL to reflect this finding in its compliance filing."

In response to YUB-YEC-1-47 during the 2021 GRA review process YEC stated the following:

> "YEC is aware that seasonal pricing can be an effective tool to reduce peak energy and capacity demand. However, YEC has not proceeded with undertaking any

> detailed analysis or assessments regarding implementation of seasonal pricing as a DSM measure. As such, no analysis can be provided at this time.
>
> While the 2017/18 GRA included forecast costs for a time-of-use rate structure and smart grid study to assess the potential for a time-of-use rate structure and associated smart grid – YEC did not proceed with undertaking this work. More specifically, in Order 2018-10 the Board found that "YEC has not provided information that persuades the Board that a study on smart grid and time-of-use rates is useful or needed. Accordingly, the Board directs YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing to this decision."
>
> Seasonal or time of use rates would drive a need to consider impacts on cost of service (new rates/rate classes would require adjustments to COS study and alter results – including possibly seeking to distinguish "winter" costs from "summer" costs); and YEC would also need to consider the ability to implement a seasonal rate structure within rate policy environment established by OIC 1995/90 and OIC 2018-220."

YEC believes that TOU can be effective, but more work is needed to understand how it could be implemented here in the Yukon. We would also need to understand how TOU could be implemented with consideration to avoidance of discrimination against lower income households.

During the joint AEY/YEC Rate Rebasing review, the utilities stated that the new CCS system will help simplify rate and billing administration, allow for the storage of more usage data, and be able to accommodate future rate design such as time of use (TOU) rates.

In AEY's 2023-24 GRA, AEY stated in AEY-JM-033 (d): "AEY will actively participate in any coordinated pursuit to provide stable and cost-effective rates to Yukoners, including the development of time-of-use rates. Time-of-use rates are typically implemented to the benefit of the system Generator, which is YEC on the YIS."

(d)

YEC addresses peak load continually. DSM is currently the program Yukon Energy manages to shift peak load. Other projects include the WH2 Uprate, Dawson Voltage

Conversion, Atlin Hydro SIS and EPA, Pumped Storage, the 2024 Resource Plan, the Dawson Distribution 3 Phase Loop, Carmacks Substation Relocate and the Substation and Distribution Load Planning Study. Yukon Energy is also working towards increasing winter dispatchable energy that can be deployed during peak load, such as a battery energy storage system (BESS).

(e)

There are a variety of means to motivate customers to use electricity more efficiently. Several are currently in the place in the Yukon, including the Government of Yukon's Good Energy program which offers rebates and other incentives for residential and commercial energy efficiency initiatives. Consumer education is also important. Educating people to avoid using electric intensive appliances at peak times can help shift peak load.

(f)

There are a variety of means to motivate customers to reduce usage at peak times. Multiple such initiatives are currently ongoing in the Yukon, including the Beat the Peak program, currently led by the Yukon Conservation Society, and Yukon Energy's Peak Smart Home program. Consumer education is also important. Educating people to avoid using electric intensive appliances at peak times can help shift peak load.

REFERENCE: **(Ref) Application p 2, pdf p.3**

ISSUE: Interim Rates

QUOTE: Through this approach, the impact of YEC's 2023 and 2024 rate increases on customer bills will be reduced, there would be no impact to residential bills throughout the winter, and greater bill stability and predictability will be provided to Yukoners. (GRA PDF p.3)

QUESTION:

a) How is there " no impact to residential bills throughout the winter"? Without the interim rate, the bill would be lower. Interim rates do impact customer bills. Please provide an sample bill reflecting the January 1 2024 interim rate increase, and a sample bill with all of the same data but without the interim rate increase. Is there a difference?

b) How can there be "no impact" to customer bills, while there is an impact to how much YEC collects from customers?

c) YEC assumes that customers prefer bill stability to lower rates. Is there anything backing up this assumption?

d) Would YEC expect customers to object to a lower rate in January 2024?

e) YEC's approach to bill stability seems to rest on the idea that customers would prefer a constant rate per KWh over an occasionaly lower rate. Does YEC believe that customers are aware of the actual cost per KWh, given that it is not expressed on the billing statement?

f) Given that usage and rates vary, is YEC's bill stability based on the idea that customers perceive that all utility costs vary linearly with kWh? Please explain how customers perceive and understand bill stability.

ANSWER:

(a)

The question asked conveniently provides the response. Mr. Yee states "Without the interim rate, the bill would be lower". Therefore, as stated by Mr. Yee, the bill would change (would be impacted) without the interim rates proposed by YEC. However, YEC's application shows that there would be no impact to residential customer bills on page 2, meaning that bills would remain stable.

(b)

There is no impact to a typical customer bill as increases in Rider J are offset by decreases in Rider F as shown in response to UCG-YEC-1-6.

(c)

YEC does not assume customers prefer bill stability to lower rates. A GRA typically requires an increase in rates to address ongoing cost pressures, including capital investments required to replace aging infrastructure and energy transition initiatives. YEC has proposed smaller bill increases more regularly than large bill increases less frequently. Aside from minimizing bill fluctuations, interim rates also start the process of bill change as soon as possible during the test years to minimize bill increases for the required true-ups when the revenue requirements are approved.

(d)

YEC believes customers would not object to lower bills in January 2024 if it didn't result in the negative consequence of a much higher increase later. However, as rates will go up over time, the question does not deal with the real situation.

(e)

YEC believes that those customers who are interested in knowing the cost per kW.h realize that it changes depending on volume of consumption.

(f)

No, YEC's bill stability approach is not based on the idea that customers perceive that all utility costs vary linearly with kW.h. YEC does not receive significant complaints from customers about this issue.

Utilities Consumers' Group
(UCG)

REFERENCE: Application dated August 31, 2023

QUESTION:

a) Please provide detailed reasons and rationale for why the application was not filed until August 2023, more than halfway through the proposed 2023 test year.

ANSWER:

(a)

The Compliance Filing for the 2021 General Rate Application was not approved by the Board until February 7, 2023. Yukon Energy commenced preparation of its 2023/24 General Rate Application as soon as feasible after that date. YEC's Board approved completion of the Application on July 20, 2023. The Application document was completed for filing on August 31, 2023.

REFERENCE: Application dated August 31, 2023

QUESTION:

a) Please provide details of all customer and stakeholder consultations conducted by Yukon Energy Corporation during development of this application prior to submitting it to the YUB.

b) Please provide specific details on how YEC's customers were informed of proposals being considered for inclusion in the application and how input from customers was used to develop details of the application.

c) Please provide all documentation related to issues discussed during these consultations and a list of all parties involved in the consultations.

d) Please confirm how and when the leadership/owners of YEC approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

ANSWER:

(a) to (c)

YEC did not conduct customer or stakeholder consultations during development of the application prior to the filing.

(d)

The Board of Directors of YEC approved filing of an application, when ready, by normal resolution at a meeting on July 20, 2023.

REFERENCE: **Cover Letter dated August 31, 2023**

"The GRA deals primarily with Yukon Energy revenues required in 2023 and 2024 to carry out its responsibilities. It does not address in any material way cost of service and general rate design matters that would require joint work with ATCO Electric Yukon (AEY)."

QUESTION:

a) Please describe YEC's responsibilities.

b) Please explain why no attempt was made to address long-standing cost of service and rate design matters in this application and when these issues will be addressed through a joint application with ATCO Electric Yukon.

ANSWER:

(a)

Yukon Energy is the main generator and transmitter of electricity in Yukon. It is responsible for ensuring the Yukon Integrated System has a supply of safe, reliable and sustainable electricity to meet Yukoner's needs.

(b)

The YEC GRA Application can only deal with revenue requirement and rate matters applicable solely to YEC. Any cost of service and rate design matters would require the YUB to establish a separate joint proceeding involving both YEC and AEY.

The following are also noted in this regard:

- In Order 2010-13 the Board did not accept the Cost of Service Study provided by the Companies noting at paragraph 29, "The Board agrees with the City of Whitehorse's view that an updated COS study approved by the Board is essential to establishing a future rate restructuring process. Therefore, the Board directs the Companies to file a joint COS study within six months of the expiry of OIC 2008/149."

- OIC 2018/220 provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time.

REFERENCE: **Cover Letter dated August 31, 2023**

> "YEC's Application identifies the necessity to increase YEC's electricity rates in 2023 and 2024 in order to meet Yukoners' need for an increasing supply of safe, reliable and sustainable electricity. Significant and timely investments in all aspects of the Yukon's electricity system – generation, transmission, distribution, storage and grid stability, and end-use – are needed to address growth in winter peak electricity loads, aging utility infrastructure, energy transition changes, as well as rising costs and capital project complexity."

QUESTION:

a) Please provide a schedule showing all forecast costs (O&M and capital) for 2023 and 2024 and which of YEC's interpretation of Yukoners' needs (safe supply, reliable supply, sustainable supply) are addressed by each of these costs.

b) Please provide a schedule that identifies aspects of the electricity system (generation, transmission, distribution, storage, grid stability and end-use) being addressed by each of the forecast capital expenditures in 2023 and 2024.

ANSWER:

(a)

Costs associated with safe, reliable and sustainable supply are inherent in all costs of YEC.

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

Additionally, work completed with capital and O&M dollars is subject to federal and territorial legislation, and electrical utility codes and standards that drive safety, reliability

and sustainability. Federal and territorial legislation is varied with key pieces of legislation impacting capital and O&M spending. Examples of significant pieces of legislation are the Yukon Environmental and Socio-economic Assessment Act, the Yukon Waters Act, the Workers' Safety and Compensation Act, the Yukon Environment Act, the Federal Fisheries Act, and the Migratory Birds Convention Act.

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

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

(b)

Aspects of the electricity system being addressed by each of the forecast capital expenditures in 2023 and 2024 are provided in the Application in Tables 5.4 and 5.5.

REFERENCE: **Cover Letter dated August 31, 2023**

"In filing this Application, YEC is aware that no one likes rate increases and that even the smallest rate increase can have an impact on some Yukoners. Average monthly bills in Yukon remain the lowest across the North, and YEC is committed to doing what it can to keep it that way."

QUESTION:

a) Please provide a schedule showing that average monthly bills in the Yukon remain the lowest across the North.

b) Please explain why it would matter to Yukoners why the monthly bills paid in other jurisdictions should matter to them if these other jurisdictions are not served by YEC.

ANSWER:

(a)

Please see Appendix 4.2 of the Application which provides the following:

- Table 4.2A-1: Residential Electricity Bills in Comparison to Yukon (1000 kWh/month consumption, Residential Non-Government, $);
- Figure 4.2A-1: Northern Residential Electricity Bill in Comparison to Yukon;
- Figure 4.2A-2: Residential Electricity Bill in Comparison to Yukon; and
- Table 4.2A-2: Small Commercial Electricity Bills in Comparison to Yukon (2000 kWh/month consumption, Commercial Non-Government, $).

(b)

The information provided demonstrates that at current levels or with proposed increases Yukon rates are lower relative to other similar jurisdictions in the north.

REFERENCE: Application, Table 1: Proposed Rate Changes and Expected Bill Impacts
Board Order 2023-1 - YEC Interim Refundable Rates
YEC's approach for the current rate application would result in a total 14.11% rate adjustment or a 6.1% ($13 per month) residential bill increase at a consumption of 1000 kWh. Board Order 2023-1 granted YEC an Interim Refundable Rate increase of 10% (Rider J) effective January 1, 2024, and no increase or decrease for 2023 test year.

QUESTION:

a) Please provide examples of residential and commercial bill increases from other jurisdictions that reflect an overall bill increase in excess of 10%.

b) Please provide specific dollar amounts (monthly and annually) that will be collected by YEC from each customer class with the 10% increase for the 2024 test year.

c) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for a YEC residential customer using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2017, January 2018, January 2019, January 2020, January 2021, January 2022, January 2023, January 2024 and January 2025 assuming that the 2023 and 2024 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

d) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2017, January 2018, January 2019, January 2020, January 2021, January 2022, January 2023, January 2024 and January 2025 assuming that the 2024 and 2024 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

e) Please provide detailed calculations of the total bill (including all riders, rate relief, and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2017, January 2018, January 2019, January 2020, January 2021, January 2022, January 2023, January 2024 and January 2025 and assuming that only 50% of the 2024

and 2025 rate adjustments proposed by YEC are approved. Please provide details of the bill calculations and indicate overall percentage changes in the total bill for each year.

ANSWER:

(a)

The Board Order 2023-23 approved an Interim Refundable Rider J increase of 10% effective January 1, 2024. This is not a bill increase. Please see responses to (c) and (e) below that show the bill changes effective January 1, 2024.

Hydro Quebec published bill comparisons for 2021 and 2022 [2023 is not available] show Edmonton and Calgary residential electricity bills increase by about 30% and 22% respectively [increase in April 2022 bill compared to April 2021 bill][1].

On February 2, 2023, the Nova Scotia Utility and Review Board (UARB) approved a rate increase of 13.8% over two years [2023 and 2024] based on the Nova Scotia Power rate application[2].

Maritime Electric, PE rate increases for the 2023 - 2025 test years reflected an actual rate/bill impact of about 10.31% increase over three years (increase of 4% charge per kWh in 2023, 2.6% increase in 2024 and 3.4% increase in 2025) for residential customers using less than 2,000 kWh per month effective from May 2023[3].

While the approved rate increases for SaskPower based for the 2022-2023 rate application is a total of 8% (4% increase effective September 2022 and a further 4% rate increase effective April 2023), the actual bill impact for a typical urban residential customer is approximately 10%.[4]

[1] Hydro Quebec- 2022 Comparison of Electricity Prices in Major North American Cities (Rates in effect April 1, 2022). 2021 Comparison of Electricity Prices in Major North American Cities (Rates in effect April 1, 2021).

[2] Nova Scotia Power Inc. (Re), 2023 NSUARB 12 (CanLII). File Number M10431

[3] Maritime Electric Company, Limited (MECL)- Prince Edward Island Regulatory & Appeals Commission Order UE23-04. Appendix A, pdf pg. 17. 6 Takeaways from Maritime Electric's latest rate increase | CBC News.

[4] Saskatchewan Rate Review Panel- Recommendations for the Minister of Crown Investments Corporation of Saskatchewan Regarding the SaskPower April 1, 2023 Rate Increase. SaskPower rate increase approved, SaskEnergy also seeking rate hike | 650 CKOM.

(b)

Please see the table for incremental revenues from YEC and AEY retail and industrial customer classes from a 10% interim refundable increase in Rider J. The table assumes the interim rate in place from January 1, 2024 to December 31, 2024.

$000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential													
Incremental Revenues with 10% increase in Rider J	$384	$290	$304	$240	$205	$173	$172	$172	$189	$231	$306	$348	$3,014
General Service													
Incremental Revenues with 10% increase in Rider J	$357	$303	$330	$281	$253	$235	$273	$258	$268	$312	$334	$382	$3,586
Industrial													
Incremental Revenues with 10% increase in Rider J	$68	$65	$70	$65	$85	$73	$75	$78	$78	$66	$77	$78	$877
Lighting													
Incremental Revenues with 10% increase in Rider J	$11	$11	$11	$11	$11	$11	$11	$11	$11	$11	$11	$11	$130
Total Incremental Revenues	$820	$669	$714	$597	$555	$491	$531	$519	$545	$619	$728	$819	$7,607

Note: Includes both YEC and AEY sales

(c) and (d)

YEC and AEY customers pay the same bills for the consumption levels requested in the question.

Please see the UCG-YEC-1-6 (c) Attachment 1.

Please note that the January 1, 2025 bill calculations assume YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application. The bill calculations do not include AEY's 2023/24 GRA final rate impact.

(e)

Please see the UCG-YEC-1-6 (e) Attachment 1.

Please note that the January 1, 2025 bill calculations assume YEC's 2023/24 GRA final rate approved effective August 1, 2024 with 50% of 2023 and 2024 revenue shortfalls are approved to be collected. The bill calculations do not include AEY's 2023/24 GRA final rate impact.

Table 1. Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Actuals														UCG-YEC-1-6 (c) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=kWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09	$0.009700	$7.76	$0.013710	$10.97	$0.000000	$0.00	$0.01635	$13.08	$0.01635	$13.08		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$12.31	16.51%	$18.45	16.51%	$18.45	22.32%	$24.95	22.32%	$24.95	41.65%	$46.55	34.08%	$38.09	34.84%	$38.94	44.84%	$50.12	55.04%	$61.52
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$10.34	9.25%	$10.34	0.00%	$0.00	1.85%	$2.07	3.01%	$3.36	3.01%	$3.36	7.19%	$8.04
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$0.80		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$5.11		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$12.99	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	10.80%	$12.07	10.80%	$12.07
11=Sum(1:10)	Total Before Regates and GST			$127.14		$133.97		$133.97		$164.09		$167.30		$167.60		$169.18		$176.43		$178.12		$193.40
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0226	-$18.1	-$0.0226	-$18.1	-$0.0226	-$18.1	-$0.0226	-$18.1
13=Sum(11:12)	Total After Rebates, before GST			$105.86		$112.69		$112.69		$142.81		$146.02		$146.32		$151.08		$158.34		$160.03		$175.30
14=13*1.05	Total After GST			$111.16		$118.33		$118.33		$149.95		$153.32		$153.64		$158.64		$166.25		$168.03		$184.07
	Change, %					*6.5%*		*0.0%*		*26.7%*		*2.2%*		*0.2%*		*3.3%*		*4.8%*		*1.1%*		*9.5%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 2. Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Actuals																UCG-YEC-1-6 (c) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11	$0.009700	$9.70	$0.013710	$13.71	$0.000000	$0.00	$0.01635	$16.35	$0.01635	$16.35		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$14.98	16.51%	$22.46	16.51%	$22.46	22.32%	$30.37	22.32%	$30.37	41.65%	$56.66	34.08%	$46.37	34.84%	$47.40	44.84%	$61.00	55.04%	$74.88
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$12.58	9.25%	$12.58	0.00%	$0.00	1.85%	$2.52	3.01%	$4.10	3.01%	$4.10	7.19%	$9.78
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.00		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$6.22		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$15.81	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	10.80%	$14.69	10.80%	$14.69
11=Sum(1:10)	Total Before Regates and GST			$154.44		$162.89		$162.89		$199.99		$204.00		$204.01		$206.36		$215.19		$216.84		$235.41
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$127.84		$136.29		$136.29		$173.39		$177.40		$177.41		$183.74		$192.57		$194.22		$212.79
14=13*1.05	Total After GST			$134.23		$143.11		$143.11		$182.06		$186.27		$186.28		$192.92		$202.20		$203.93		$223.43
	Change, %					*6.6%*		*0.0%*		*27.2%*		*2.3%*		*0.0%*		*3.6%*		*4.8%*		*0.9%*		*9.6%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 3. Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Actuals																UCG-YEC-1-6 (c) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13	$0.009700	$11.64	$0.013710	$16.45	$0.000000	$0.00	$0.01635	$19.62	$0.01635	$19.62		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$17.80	16.51%	$26.70	16.51%	$26.70	22.32%	$36.09	22.32%	$36.09	41.65%	$67.34	34.08%	$55.10	34.84%	$56.33	44.84%	$72.50	55.04%	$88.99
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$14.96	9.25%	$14.96	0.00%	$0.00	1.85%	$2.99	3.01%	$4.87	3.01%	$4.87	7.19%	$11.63
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.20		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$7.39		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$18.79	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	10.80%	$17.46	10.80%	$17.46
11=Sum(1:10)	Total Before Regates and GST			$183.40		$193.51		$193.51		$237.80		$242.61		$242.45		$245.44		$255.93		$257.72		$279.77
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$156.80		$166.91		$166.91		$211.20		$216.01		$215.85		$222.82		$233.31		$235.10		$257.15
14=13*1.05	Total After GST			$164.64		$175.26		$175.26		$221.76		$226.81		$226.65		$233.96		$244.98		$246.86		$270.01
	Change, %					*6.4%*		*0.0%*		*26.5%*		*2.3%*		*-0.1%*		*3.2%*		*4.7%*		*0.8%*		*9.4%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 4. Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Actuals																UCG-YEC-1-6 (c) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15	$0.009700	$13.58	$0.013710	$19.19	$0.000000	$0.00	$0.01635	$22.89	$0.01635	$22.89		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$20.63	16.51%	$30.93	16.51%	$30.93	22.32%	$41.81	22.32%	$41.81	41.65%	$78.02	34.08%	$63.84	34.84%	$65.27	44.84%	$84.00	55.04%	$103.11
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$17.33	9.25%	$17.33	0.00%	$0.00	1.85%	$3.47	3.01%	$5.64	3.01%	$5.64	7.19%	$13.47
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.40		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$8.56		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$21.77	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	10.80%	$20.23	10.80%	$20.23
11=Sum(1:10)	Total Before Regates and GST			$212.36		$224.13		$224.13		$275.60		$281.21		$280.90		$284.52		$296.67		$298.60		$324.14
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$185.76		$197.53		$197.53		$249.00		$254.61		$254.30		$261.90		$274.05		$275.98		$301.52
14=13*1.05	Total After GST			$195.05		$207.41		$207.41		$261.45		$267.34		$267.02		$274.99		$287.76		$289.78		$316.60
	Change, %					*6.3%*		*0.0%*		*26.1%*		*2.3%*		*-0.1%*		*3.0%*		*4.6%*		*0.7%*		*9.3%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 1. Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh	Actuals														UCG-YEC-1-6 (e) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	800	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12	$0.1214	$97.12
3=kWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$4.48	-$0.000110	-$0.09	-$0.000110	-$0.09	$0.009700	$7.76	$0.013710	$10.97	$0.000000	$0.00	$0.01635	$13.08	$0.01635	$13.08		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$12.31	16.51%	$18.45	16.51%	$18.45	22.32%	$24.95	22.32%	$24.95	41.65%	$46.55	34.08%	$38.09	34.84%	$38.94	44.84%	$50.12	44.94%	$50.23
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$10.34	9.25%	$10.34	0.00%	$0.00	1.85%	$2.07	3.01%	$3.36	3.01%	$3.36	2.18%	$2.43
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$5.44	-$0.006800	-$5.44	-$0.006800	-$5.44		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$0.80		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$5.11		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$12.99	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	8.30%	$9.28	10.80%	$12.07	10.80%	$12.07
11=Sum(1:10)	Total Before Regates and GST			$127.14		$133.97		$133.97		$164.09		$167.30		$167.60		$169.18		$176.43		$178.12		$176.51
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0266	-$21.3	-$0.0226	-$18.1	-$0.0226	-$18.1	-$0.0226	-$18.1	-$0.0226	-$18.1
13=Sum(11:12)	Total After Rebates, before GST			$105.86		$112.69		$112.69		$142.81		$146.02		$146.32		$151.08		$158.34		$160.03		$158.41
14=13*1.05	Total After GST			$111.16		$118.33		$118.33		$149.95		$153.32		$153.64		$158.64		$166.25		$168.03		$166.33
	Change, %					*6.5%*		*0.0%*		*26.7%*		*2.2%*		*0.2%*		*3.3%*		*4.8%*		*1.1%*		*-1.0%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 2. Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh	Actuals																UCG-YEC-1-6 (e) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	-	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00	$0.1282	$0.00
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$5.60	-$0.000110	-$0.11	-$0.000110	-$0.11	$0.009700	$9.70	$0.013710	$13.71	$0.000000	$0.00	$0.01635	$16.35	$0.01635	$16.35		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$14.98	16.51%	$22.46	16.51%	$22.46	22.32%	$30.37	22.32%	$30.37	41.65%	$56.66	34.08%	$46.37	34.84%	$47.40	44.84%	$61.00	44.94%	$61.14
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$12.58	9.25%	$12.58	0.00%	$0.00	1.85%	$2.52	3.01%	$4.10	3.01%	$4.10	2.18%	$2.96
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$6.80	-$0.006800	-$6.80	-$0.006800	-$6.80		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.00		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$6.22		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$15.81	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	10.80%	$14.69	10.80%	$14.69
11=Sum(1:10)	Total Before Regates and GST			$154.44		$162.89		$162.89		$199.99		$204.00		$204.01		$206.36		$215.19		$216.84		$214.85
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$127.84		$136.29		$136.29		$173.39		$177.40		$177.41		$183.74		$192.57		$194.22		$192.23
14=13*1.05	Total After GST			$134.23		$143.11		$143.11		$182.06		$186.27		$186.28		$192.92		$202.20		$203.93		$201.84
	Change, %					*6.6%*		*0.0%*		*27.2%*		*2.3%*		*0.0%*		*3.6%*		*4.8%*		*0.9%*		*-1.0%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 3. Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	Actuals														UCG-YEC-1-6 (e) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	200	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64	$0.1282	$25.64
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$6.72	-$0.000110	-$0.13	-$0.000110	-$0.13	$0.009700	$11.64	$0.013710	$16.45	$0.000000	$0.00	$0.01635	$19.62	$0.01635	$19.62		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$17.80	16.51%	$26.70	16.51%	$26.70	22.32%	$36.09	22.32%	$36.09	41.65%	$67.34	34.08%	$55.10	34.84%	$56.33	44.84%	$72.50	44.94%	$72.66
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$14.96	9.25%	$14.96	0.00%	$0.00	1.85%	$2.99	3.01%	$4.87	3.01%	$4.87	2.18%	$3.52
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$8.16	-$0.006800	-$8.16	-$0.006800	-$8.16		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.20		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$7.39		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$18.79	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	8.30%	$13.42	10.80%	$17.46	10.80%	$17.46
11=Sum(1:10)	Total Before Regates and GST			$183.40		$193.51		$193.51		$237.80		$242.61		$242.45		$245.44		$255.93		$257.72		$255.34
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$156.80		$166.91		$166.91		$211.20		$216.01		$215.85		$222.82		$233.31		$235.10		$232.72
14=13*1.05	Total After GST			$164.64		$175.26		$175.26		$221.76		$226.81		$226.65		$233.96		$244.98		$246.86		$244.35
	Change, %					*6.4%*		*0.0%*		*26.5%*		*2.3%*		*-0.1%*		*3.2%*		*4.7%*		*0.8%*		*-1.0%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

Table 4. Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	Actuals																UCG-YEC-1-6 (e) Assumptions			
			Jan-17		Jan-18		Jan-19		Jan-20		Jan-21		Jan-22		Jan-23		Jul-23		Jan-24		Jan-25	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates																					
1	Customer Charge (per month)		$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=kWh*Base rate	First Block Energy (kWh)	1,000	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=kWh*Base rate	Second Block Energy (kWh)	400	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28	$0.1282	$51.28
4=kWh*Rider F rate	Rider F (kWh) [Fuel Price Rider]		-$0.005600	-$7.84	-$0.000110	-$0.15	-$0.000110	-$0.15	$0.009700	$13.58	$0.013710	$19.19	$0.000000	$0.00	$0.01635	$22.89	$0.01635	$22.89		$0.00		$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)		11.01%	$20.63	16.51%	$30.93	16.51%	$30.93	22.32%	$41.81	22.32%	$41.81	41.65%	$78.02	34.08%	$63.84	34.84%	$65.27	44.84%	$84.00	44.94%	$84.19
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)			$0.00		$0.00		$0.00	9.25%	$17.33	9.25%	$17.33	0.00%	$0.00	1.85%	$3.47	3.01%	$5.64	3.01%	$5.64	2.18%	$4.08
7=kWh*Rider E rate	Rider E (kWh) [LWRF Rider]		-$0.006800	-$9.52	-$0.006800	-$9.52	-$0.006800	-$9.52		$0.00		$0.00		$0.00		$0.00		$0.00	$0.000000	$0.00	$0.000000	$0.00
8=kWh*Rider S rate	AEY Rider S (kWh)																		$0.001000	$1.40		
9=(1+2+3)*Rider R1 rate	AEY Rider R1 (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00	-4.57%	-$8.56		$0.00		$0.00		$0.00
10=(1+2+3)*Rider R rate	AEY Rider R (%)		11.62%	$21.77	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	8.30%	$15.55	10.80%	$20.23	10.80%	$20.23
11=Sum(1:10)	Total Before Regates and GST			$212.36		$224.13		$224.13		$275.60		$281.21		$280.90		$284.52		$296.67		$298.60		$295.83
	Less: Rebates																					
12=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0266	-$26.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6	-$0.0226	-$22.6
13=Sum(11:12)	Total After Rebates, before GST			$185.76		$197.53		$197.53		$249.00		$254.61		$254.30		$261.90		$274.05		$275.98		$273.21
14=13*1.05	Total After GST			$195.05		$207.41		$207.41		$261.45		$267.34		$267.02		$274.99		$287.76		$289.78		$286.87
	Change, %					*6.3%*		*0.0%*		*26.1%*		*2.3%*		*-0.1%*		*3.0%*		*4.6%*		*0.7%*		*-1.0%*

Notes:
1. Income Tax Rebate was discontinued as of April 1, 2019, therefore not included in the calcualtions.
2. The January 1, 2025 bill calculation assumes YEC's 2023/24 GRA final rate approved effective August 1, 2024 as proposed in the Application.
3. The January 1, 2025 bill calculation does not include AEY's 2023/24 GRA final rate impact.
4. The Yukon government provided Inflation Relief Rebate from March through December 2022.

REFERENCE: **Cover Letter dated August 31, 2023; Application page 2**

> "That's why as part of this Application, YEC is seeking the YUB's support to approve the timing for implementation of YEC's interim rate increases and YEC's final rate adjustment to occur when other charges on electricity bills are expected to be reduced and/or expire. Through this approach, the impact of YEC's 2023 and 2024 rate increases on customer bills will be reduced and there would be no impact on residential bills throughout the winter, and greater bill stability and predictability will be provided to Yukoners."

QUESTION:

a) Please explain fully YEC's conclusion that the proposed rate increase impact on bills will be reduced by implementing interim rate increases and then a final rate increase. How does implementing any rate increase get justified by being offset by the elimination of temporary rate riders?

b) Please explain how YEC accounts for affordability when proposing rate increases and how these rate increases are implemented. Does YEC consider existing rates and bills paid by Yukoners affordable?

ANSWER:

(a)

Interim rates help to enhance customer bill stability, reducing the need for large bill increases to implement new rates plus implement higher true-up rate riders (to recover revenue shortfalls during each test year) when all approvals are finalized by the Board.

When interim rates are applied, YEC is able to recover costs earlier. Due to the compounding effect, adding the bill impacts together results in a lower overall impact on bills as a percentage. YEC's proposal was for a bill impact of 3.0% on October 1, 2023 and 3.0% on August 1, 2024, for a total of 6.1% on residential customer bills with a monthly consumption of 1,000 kWh. If no interim rates are collected, the impact on residential customer bills on August 31, 2024 would have been close to 10% compared to 6.1% proposed in the Application.

YEC is not justifying rate increases by offsetting impacts of temporary riders. Justification for rate increases are discussed thoroughly in the Application.

(b)

It is not possible to have a simple definition of affordability that everyone will agree with. YEC attempts to keep bills affordable by keeping rate increases within a reasonable range of inflation. The bill impacts from this GRA are less than inflation since the last GRA test year of 2021.

REFERENCE: **Cover Letter dated August 31, 2023**

"In an effort to promote regulatory efficiency, YEC proposes to limit the number of intervener Information Requests (IRs) to a maximum of 50, including sub-parts."

Mandate of the Yukon Utilities Board
(https://yukonutilitiesboard.yk.ca/about/mandate-of-the-board/)
"Public Participation
As an open and transparent quasi-judicial body, the Board welcomes and encourages public participation in its hearings. Public participation ensures that all issues and perspectives come to the Board's attention in a transparent process. Hearings allow the Board to make a fully informed decision with significant public input."

[…]
"Applicants must provide information to support their requests, provide supplemental information when required, and respond to pre-hearing questions from the Board and interveners."

QUESTION:

a) Please explain how YEC's proposed restriction on the number of questions parties may ask with respect to the application allows the YUB to fulfill its mandate to address all issues in a transparent process.

b) Please identify where in the YUB's mandate or its Rules of Practice there is provision to limit the questions asked to clarify the specifics of an application and permit a full and satisfactory understanding of the matters to be considered.

ANSWER:

(a)

As noted in YEC's cover letter, this approach to ensuring regulatory efficiency has been implemented in other jurisdictions and therefore is seen as being something consistent

with a rate regulator fulfilling its mandate to address all relevant issues in a transparent matter.

Yukon Energy has received a material number of information requests over the past several General Rate Applications. In many cases such requests are repetitive or not directly related to the matters to be determined by the Board. Limiting the number of information requests for intervenors would help ensure that intervenor questions are focused on matters that they intend to raise during the proceeding and/or are directly relevant to the issues raised in the application. This would help ensure an efficient and focused process, which is of particular importance in Yukon's relatively small regulated electrical system.

(b)

Pursuant to Rule 4, "In any proceeding, the Board may issue directions on procedure which will govern the conduct of that proceeding." Such directions could include procedures to ensure regulatory efficiency by limiting the number of information requests provided by intervenors.

REFERENCE: **Application, page 3; page 1-4**

"The Yukon's peak demand for electricity has increased by 23% in the last five years [from 2017 to 2022] and this trend is expected to continue with an additional 36% increase in non-industrial peak by 2030. Meeting these peaks demands for power in the short term requires the rental and operation of diesel generators each winter until new sources of dependable capacity can be built or connected to the Yukon grid. As more Yukoners begin using electricity for heat, the security provided by these rental units is more significant than ever before to ensure a reliable supply of the electricity needed to keep Yukoners' homes warm and safe during the winter months."

QUESTION:

a) Please provide a demand curve for 2017-2024 showing layers of the end use of electricity that make up that demand (e.g., by rate class and how much of the residential demand is related to electricity for space heating).

b) Please provide details on how the impact of YEC's 2022-2030 Demand Side Management program are reflected in what the electricity demand trend will be for 2023, 2024 and beyond.

ANSWER:

(a)

Yukon Energy does not forecast the system peak (demand curve) by end use or by rate class (residential, commercial). Yukon Energy uses a regression model to forecast total Wholesale peak demands.

(b)

The estimated impact from Yukon Energy's Demand Side Management program is about 0.1 MW for the winter of 2023/24 and up to 0.6 MW for the winter of 2024/25. The portfolio will be scaled up, including the addition of new programs, to provide 7 MW of reduced peak by the winter of 2030/31 (see Application, Section 5.2A-2).

REFERENCE: **Application, page 3**

"These changes in end-user behaviour put increased pressure and strain on the electricity system and require significant and urgent investments in all aspects of the Yukon's electricity system. Supporting these climate objectives requires significant and urgent investments in all aspects of Yukon's electricity system."

QUESTION:

a) While climate change issues are needing to be addressed, why is it suddenly urgent that Yukoners now spend so much more to build an electricity system for what some think is needed in the future? How does YEC know that the current trend to transition to more electricity use will be the best choice in the future? Why is YEC planning to spend so much for a future that is far from certain?

b) How does using additional diesel generation to serve a perceived growing need for electricity fit with climate change concerns? Why isn't YEC spending more to provide an incentive for Yukoners to use less electricity?

c) Please provide details on how other electricity utilities throughout Canada are addressing the transition to higher electricity use.

ANSWER:

(a) and (c)

Hydro-based electric utilities in Canada (e.g., BC Hydro, Manitoba Hydro, Hydro-Quebec), have each recently announced planning activities to materially increase their systems' capabilities to meet increased electricity requirements arising from the transitions needed to address climate change issues.

The Application (pages 2-4) summarizes the key pressures facing Yukon Energy at this time that are driving the need for urgent investments, including:

(i) **Steady growth in peak electricity demand –** Yukon's peak demand for electricity has increased by 23% in the last five years [from 2017 to 2022] and an additional 36% increase in non-industrial peak is expected by 2030).

(ii) **The need to upgrade or replace aging generation, transmission and distribution infrastructure -** Yukon's electricity system is nearing end-of-life and needs significant upgrades or replacement at the same time, water licences for each of our three hydro facilities and permits for many of our thermal facilities will need to be renewed.

(iii) **Transition from reliance on fossil fuels in Yukon's heating and transportation sectors to clean energy alternatives** - Changes in end-user behaviour driven by local and national objectives to reduce GHG emissions are putting increased pressure and strain on the electricity system and require significant and urgent investments in all aspects of the Yukon's electricity system.

(iv) **The impact of rising costs and project complexity** – Yukon Energy faces external pressures such as inflation, increased labour costs, and supply chain constraints; combined with ongoing increased complexity of project implementation.

As noted in the Application (p. 4), "These pressures reflect our new reality: a changing world with changing demands for how Yukoners use and produce electricity. This future will depend on a more complex electrical system, one that will require significant generation, transmission and distribution system upgrades to support electrification;" and "As the primary generator and transmitter of electricity in Yukon, it is YEC's responsibility to lead these changes."

In summary, there is no uncertainty regarding the need to address these issues at this time; and there is no reasonable basis for Yukon Energy, an isolated, northern utility, to delay proceeding with prudent and necessary actions that will take considerable time to implement.

(b)

Diesel generation is required to meet peak capacity requirements so that Yukoners have reliable electricity service during the coldest days of the year.

Page 3 of the Application notes that investments are required in all aspects of Yukon's electricity system, including generation, transmission, distribution, storage and grid

stability and end-use programs to bolster the capacity of the Yukon's generation, transmission and distribution resources now and in the future. Investments in smart programs and technologies, including demand-side management (DSM) programs, are also needed to better manage and shift system peaks when products like electric vehicle chargers, electric baseboards and water heaters, and heat pumps are used.

It is specifically noted that YEC is investing in programs to encourage and help Yukoners shift their electricity use during peak demands. The 2023/24 GRA includes $ 2.77 million in net spending (after contributions) on DSM program to help Yukoners take an active role in reducing peak demand for power by shifting their electricity use to off-peak times. Further detail on DSM programs being pursued is provided in Appendix 5.2A of the Application (see Section 5.2A-2).

REFERENCE: **Application, pages 4 - 5**

"Rate increases in Yukon are needed over the next five to ten years to make investments to meet our growing demands for electricity. They are needed:

[…]

• "To make the electricity system resilient to climate change and to make repairs in the aftermath of climate events;"

QUESTION:

a) Please explain what YEC means by making the electricity system resilient to climate change.

b) Please provide details of which O&M and capital expenditures in 2023 and 2024 are related to making the electricity system resilient to climate change. Provide details on how each expenditure caters to resiliency to climate change.

c) Please provide details of expenses incurred by YEC between 2017 and 2022 related to climate events that needed to be recovered through rates.

ANSWER:

(a)

Yukon Energy is referencing its ongoing work to better understand, predict and address impacts on our activities and infrastructure due to climate change and extreme weather.

Climate change is causing significant changes to seasonal and annual patterns in temperature, precipitation, and extreme events, globally and locally. Climate change impacts can pose significant risk to Canada's electricity sector, with considerable impacts to infrastructure, revenue, and supply. The north is experiencing greater climate change impacts than other southern locations, which increases risk to our electricity grid, infrastructure, and stakeholders. Climatic changes are disrupting the timing, frequency and intensity of weather patterns which can impact the delivery of hydroelectricity and exacerbate other known risks in the organization. YEC has been reviewing relevant information and studies on these matters, including a study on Distributed Hydrological Modelling System to Support Hydroelectric Production in Northern Environments under

Current and Changing Climate Conditions completed for Yukon Energy in 2020 by Centre Eau Terre Environnement Institut national de la recherche scientifique.

Yukon Energy is developing our Climate Change Adaptation Implementation Plan to better understand, predict and address impacts on our activities and infrastructure due to climate change and extreme weather. By resilience, in addition to building this understanding, we are developing capacity to withstand or to recover quickly from those challenges. We are thereby minimizing the risks to YEC's ability to deliver on its core mission of enabling Yukon's prosperity with sustainable, cost effective and reliable electricity by building and maintaining infrastructure to withstand the effects of major climate events.

(b)

It is important to emphasize that engineering practice has evolved to incorporate climate change considerations into design. Therefore, asking to specify expenditures in 2023 and 2024 that are making the electricity system resilient to climate change is difficult because there are generally not specific climate change resiliency projects. But, broadly speaking any investment in our civil assets (dams, building, foundations, roads, poles, wires. etc.) will make our system more resilient to climate change as climate change is considered in design.

To reinforce that climate change considerations are a requirement for design and engineering processes generally, Engineers Canada has created guidelines:

1. "Public Guideline: Principles of Climate Adaptation and Mitigation for Engineers." *Engineers Canada*, engineerscanada.ca/public-guideline-principles-of-climate-adaptation-and-mitigation-for-engineers. Accessed 8 Nov. 2023.

2. *Climate Change and Extreme Weather Events - Engineers Canada*, engineerscanada.ca/sites/default/files/public-policy/climatechange-en.pdf. Accessed 8 Nov. 2023.

One specific project with an emphasis on making the system more resilient to climate change is the Lewes Gate Automation (included in Table 5.7). There is concern as to the current stability of this asset as it has been compromised partly due to an increase in annual precipitation in the area. Increased precipitation can create unstable slopes and

impact buildings and water courses. Understanding the increased vulnerability here is critical to avoid a greater failure and subsequent flooding downstream.

YEC is also considering a more specific Climate Change Adaptation Implementation Plan that includes the following potential projects:

- Assess permanent flood protection options for P125;
- Assess WRGS critical spare requirements;
- Marwell flood prevention design;
- Engineering assessment on basalt wing wall reinforcement at WRGS;
- Relocation of Lewes station service;
- Assessment of Aishihik Dam refurbishment options;
- Assessment of Canyon control structure refurbishment;
- Repair stop logs/culverts at Aishihik dam;
- Automate Canyon control structure valves and fiber install;
- Wind modelling at Aishihik Lake; and
- Condition assessment of Aishihik discharge portal.

The timing and budgets of the above listed projects will be determined as part of future capital planning processes.

(c)

YEC costs were incurred because of climate events including the damage and immediate response actions undertaken regarding the 2022 and 2023 Rockslides at Mayo, the Southern Lakes flooding in 2021 and the increasing number of forest fires. Some of these costs are included in ‘Annual Costs’ in the RFID Continuity Schedule Table 3.11.1. Also see YUB-YEC-1-53.

REFERENCE: **Application, page 1-2**

"All investments in Yukon's electricity system, unless offset by government funding, must be included in the Yukon's electricity rates."

QUESTION:

a) Please confirm YEC's understanding that it has a choice of when costs are included in its proposed revenue requirement to be recovered in rates.

ANSWER:

(a)

Not confirmed. In order to carry out its mandate, YEC is required to apply to the Yukon Utilities Board for the approvals necessary to recover its costs incurred in GRA test years, including its approved return on rate base. Failure to meet this requirement would undermine YEC's ability to provide sustained, reliable and affordable service to Yukoners.

REFERENCE: Application, page 1-3

"YEC is requesting incremental rate increases on October 1, 2023 and January 1, 2024 and in August 2024, to allow it to continue to provide Yukoners with an increasing supply of safe, reliable and sustainable electricity."

QUESTION:

a) Please explain how three rate increases over ten months contributes to stable electricity costs for Yukoners and addresses the affordability issues faced by Yukoners.

b) Please provide studies, surveys, etc. that YEC has undertaken in the last decade to get a better understanding on affordability issues related to electricity costs and how YEC has addressed the findings of these studies and surveys.

ANSWER:

(a)

It is not the rate increases that impacts electricity costs for Yukoners, but the bill impacts. Where possible, YEC's proposed rate increases were timed with rider reductions or expirations, thereby reducing the bill impact. The result was a proposal for a 3% bill impact in October 2023 and a 3% bill impact in August 2024. Without this interim approach, the proposed bill impact would have been 9% in August 2024. YEC considers smaller, more regular increases more stable than a one-time larger increase.

(b)

In 2016, an Electricity Values Survey was conducted by the Yukon Bureau of Statistics on behalf of Yukon Energy. The survey was completed as part of Yukon Energy's 2016 Resource Plan. The objective of the survey was to generate information on Yukon residents' perspectives on factors that needed to be considered in planning for Yukon's future electricity needs.

The Yukon Bureau of Statistics conducted the survey using a Computer Assisted Telephone Interviewing (CATI) system. A stratified random sample of 4,534 households representing one-third of the total eligible Yukon households at the time (13,591) was selected to complete the CATI survey. Only one person per household could complete the survey. The overall weighted response rate for the survey was 63.2% indicating that the results were a good representation of Yukon households.

Respondents ranked four major factors in order of importance to Yukon Energy's future projects. Environmental Protection was ranked first by 44 percent of respondents, followed by Cost (23 percent), Reliability (21 percent), and Social Responsibility (8 percent). In contrast to the importance given to Yukon Energy's projects, when respondents were asked to rank five factors that influence their own home heating system selection, cost was the most important factor (chosen first by 45% of respondents) to influence a respondent's home heating selection. Respondents' selection of home heating system was more influenced by cost than all four other factors (safety, environmental concerns, comfort, and ease of maintenance) combined.

No similar Electricity Values Survey has been completed by Yukon Energy since then, however, concerns about the affordability of electricity rates, rising electricity costs, and project impacts on electricity rates has been raised during public engagement activities hosted by Yukon Energy on electricity projects since then including: the proposed new thermal facility (2019); the 10-Year Renewable Electricity Plan (2020); the grid-scale battery project (2020); Riverside substation expansion project (2021); and Dawson diesel replacement and relocation project (2021).

To address these comments, Yukon Energy has sought government grant funding to buy-down the cost of electricity projects it has undertaken and reduce the cost of the project included in rates. Examples include grant funding that has been received in recent years for:

i. The Mayo to McQuesten Transmission Line Replacement Project. In 2019, the Government of Canada announced a contribution of $22.7 million towards the project through the Green Infrastructure Stream (GIS) of the *Investing in Canada* infrastructure plan. Yukon Development Corporation also provided $3.5 million towards planning costs for the project (formerly the Stewart to Keno City Rehabilitation Project).

ii. The Peak Smart Pilot Project. In 2019, the Government of Canada announced $650,000 in funding for the project from Natural Resources Canada's Smart Grid Program.

iii. Peak Smart Home. In 2023, YEC secured $100,000 in funding from the Government of Canada's Northern REACHE program and $500,000 from the Government of Yukon's Innovative Renewable Energy Initiative.

iv. The Grid-Scale Battery Project in Whitehorse. In 2019, the Government of Canada announced $16.5 million in funding for the battery project through the Green Infrastructure Stream (GIS) of the Investing in Canada infrastructure plan.

Furthermore, in each of its last two General Rate Applications (2021) and (2023/2024), Yukon Energy has proposed strategies to reduce the impact of interim and final rate adjustments on electricity bills by asking the Yukon Utilities Board that they be applied to electricity bills when other charges on were expected to be reduced to zero or removed from bills. With this approach, Yukon Energy has attempted to provide bill stability and predictability to Yukoners.

REFERENCE: **Application, Table 1-2 - Summary of Revenue and Cost Changes, page 1-7**

Independent Power Production (IPP) Cost Charges

QUESTION:

a) Please explain the difference between the $3.085 million added purchase power cost and the amount saved on thermal power production. Is this the $1.262 million IPP gap cost charges?

b) Since the IPP program is a YTG promoted program offered through our public utility corporation, please explain why Yukon Development Corporation is not paying this shortfall rather than the ratepayers.

ANSWER:

(a)

The cost of $3.085 million for 2024 reflects forecast power purchase costs from IPPs. The estimated reduction in 2024 test year long-term average thermal generation cost from IPP deliveries is $1.822 million [which is about 59% of the total IPP purchase cost for 2024]. The difference between $3.085 million added power purchase cost and $1.822 million LTA thermal reduction is $1.262 million – this is the net cost from IPPs.

OIC 2021-16 requires that thermal generation fuel costs in rates be determined based on long-term average renewable source availability. On a long-term average basis, IPPs displace about 59% of thermal generation [please see the responses to YUB-YEC-1-33 and YUB-YEC-1-34]. These thermal displacement benefits would not materialize in most years as the IPP generations mostly displace hydro generation during normal and high water years [i.e., the benefits from IPPs will be lower than 59% thermal displacement]. During lower water/drought conditions, the IPP deliveries will be used to supply the firm load and normally do not displace hydro, but help to avoid using thermal generation.

(b)

Yukon government's Independent Power Production (IPP) Policy was adopted in October 2015, and reviewed and updated by Yukon government in October 2018. One of the key elements of the IPP Policy was to create a framework for the Standing Offer Program (SOP) designed by YG.

Section 4 of the IPP SOP Rules state, "All payments under an Electricity Purchase Agreement (EPA) will be administered by the applicable Utility entering into the EPA. All EPAs with Developers of Projects proposing to interconnect to the Yukon Integrated System shall be entered into with Yukon Energy Corporation and all EPAs with Developers of Projects proposing to interconnect to the Watson Lake Grid shall be entered into with ATCO Electric Yukon."

A principle of the IPP SOP is also to "provide for a Standard Form Electricity Purchase Agreement (Standard Form EPA), being the contract for the sale by such Project of electricity by the Developer to the applicable Utility." Article 4 of the Standard Form EPA between Yukon Energy and Developers of Projects proposing to interconnect to the Yukon Integrated System outlines Yukon Energy's (i.e., the Buyer's), and the Developer's (i.e., the Seller's) Purchase and Sale Obligations. Article 5 of the Standard Form EPA outlines the Price and Payment Terms.

In terms of the inclusion of IPP purchase costs in Yukon Energy's electricity rates, Section 2 (1), Costs recoverable by electrical utility, of Order in Council 2019/025 Direction to the Yukon Utilities Board (Independent Power Production) outlines the following:

2. Costs recoverable by electrical utility
    1) In setting rates that an electrical utility is permitted to charge, the board must allow the utility to recover the costs described in subsection (2) if the electricity purchase agreement in respect of which the costs are incurred provides for the matters set out in sections 3 to 6.

    2) For the purposes of subsection (1), the costs are the following:
        a) the cost of purchasing electricity under an electricity purchase agreement;

b) third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement;

c) the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

3. Price for electricity under electricity purchase agreement

2) The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility's average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

4. Annual CPI adjustment

1) The price paid by an electrical utility for a kWh of electricity under an electricity purchase agreement is to be adjusted annually in accordance with subsection (2) or (3).

…

3) In the case of an on-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with 50% of the percentage increase, if any, in the CPI.

5. Compensation

1) An electricity purchase agreement is to provide for reasonable compensation to be paid by the electrical utility to the owner of the independent power production facility in the event that the facility is unable to deliver electricity to the utility as a result of damage to, or a failure of, infrastructure or equipment for which the utility is responsible.

2) An electricity purchase agreement need not provide for reasonable compensation to be paid by the utility to the owner of the facility in the event that the facility is unable to deliver electricity to the utility as a result of a planned outage.

6. Term of electricity purchase agreement

The term of an electricity purchase agreement is to be at least 20 years.

In terms of Yukon Energy's applied for IPP costs for inclusion in the 2023 / 2024 General Rate Application, all conditions of the OIC have been met.

REFERENCE: Application, page 1-9

"YEC is requesting approval of an IPP Purchase Cost Deferral Account that captures variances in IPP purchase costs included in the test year revenue requirements and actual purchase costs offset by IPP LTA thermal displacement benefits calculated using 59% LTA thermal displacement benefits."

QUESTION:

a) Please explain where the incentive is for YEC to as accurately as possible forecast IPP purchase costs for recovery in rates if a deferral account is put in place.

ANSWER:

(a)

Please see the detailed justification for this account provided in Section 3.6.4 of the Application. As reviewed below, this deferral account is needed to implement OIC requirements. The GRA review processes provide ample opportunity for review as to the accuracy of IPP forecasts for GRA test years.

The IPP deferral account has been implemented to comply with OIC 2019/25; and defers the variances between approved power purchase costs in rates and actual purchase costs [capital related costs are recovered through depreciation expense and rate base].

- Section 2 of OIC 2019/25 requires the Board to allow the utility to recover the cost of purchasing electricity under an electricity purchase agreement, as well as third party consultant costs (including legal fees) incurred by the utility in relation to the development and implementation of the agreement, and the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

- Subsection 3(1) of OIC 2019/25 states that the price for a kWh under an "on-grid" purchase is to be based on utility's "average blended fuel price per kWh for thermal generation most recently approved by the board before the date in which the

agreement takes effect" and subsection 4(3) states that the purchase price is increased each year by 50% of the Consumer Price Index (CPI).

OIC 2019/25 requirements apply each year, regardless of whether YEC has been able to address specific adjustments needed in rates through a GRA process. Accordingly, a deferral account mechanism is needed to deal with variances that arise between YEC's costs incurred and its ability to recover these costs through rates.

Section 3.6.4 of the Application notes that the 2021 GRA included IPP purchases with a total cost less than $400 based on actuals for 2021; while the actual cost of IPP purchases in 2022 was $0.312 million higher than the cost included in the rates. As the number of IPP connections is evolving after 2021, the volume and the price of the IPP purchases will continue to change annually compared to what is approved in the rates.

REFERENCE: Application, Sales and Generation – Overview, page 2-1
Minto Mine care and maintenance

QUESTION:

a) Please provide details of the amounts collected by YEC in 2023 from Minto mine and forecasted to be collected in 2024 to pay for the power used for care and maintenance of Minto mine.

b) Please provide details of from who these costs will be recovered.

c) Please provide details of the increase in wholesale sales (volumes and dollars) in 2023 and 2024.

d) Is YEC proposing a new updated wholesale rate in this application? If not, why not?

ANSWER:

(a) and (b)

Please see the response to UCG-YEC-1-22 (a).

(c)

Wholesale sales are shown in Table 2.1. Wholesale sales are forecast to increase by 7.8 GW.h ($0.643 million) in 2023 over 2021 approved and 4.6 GW.h ($0.379 million) in 2024 over 2023. The increases are primarily due to population growth as well as increased consumption from electrification.

(d)

YEC is not proposing a new updated wholesale rate in this application. Updated wholesale rates would only be considered by the Board in a Phase 2 proceeding.

REFERENCE: Application, Sales and Generation – Overview, page 2-2
Overall total firm generation load

QUESTION:

a) Please provide a table demonstrating for 2023 and 2024 the firm generation load amounts and dollars to be collected from each ratepayer group, including the mines.

ANSWER:

(a)

Please see the table below for the requested information.

Description	GRA Forecast 2023 Forecast	GRA Forecast 2024 Forecast
Residential		
Sales in MWh	17,693	18,090
Revenue, including existing Rider J ($000s)	3,408	3,520
Incremental 2023/24 GRA Revenues ($000s)	228	526
Total Revenues ($000s)	3,635	4,046
General Service		
Sales in MWh	38,569	44,698
Revenue, including existing Rider J ($000s)	8,447	9,675
Incremental 2023/24 GRA Revenues ($000s)	564	1,445
Total Revenues ($000s)	9,011	11,120
Industrial		
Sales in MWh	75,045	69,368
Revenue, including existing Rider J ($000s)	12,799	11,507
Incremental 2023/24 GRA Revenues ($000s)	873	1,767
Total Revenues ($000s)	13,673	13,274
Lighting		
Sales in MWh	177	177
Revenue, including existing Rider J ($000s)	114	114
Incremental 2023/24 GRA Revenues ($000s)	8	17
Total Revenues ($000s)	122	131
Total Company - Firm Retail & Ind.		
Sales in MWh	131,484	132,333
Revenue, including existing Rider J ($000s)	24,768	24,816
Incremental 2023/24 GRA Revenues ($000s)	1,672	3,754
Total Revenues ($000s)	26,440	28,571
Wholesale sales		
Sales in MWh	351,291	355,857
Revenue, including existing Rider J from AEY sales ($000s)	49,253	49,537
Incremental 2023/24 GRA Revenues from AEY sales ($000s)	4,995	11,566
Total Revenues ($000s)	54,248	61,103
Total Company - Firm		
Sales in MWh	482,775	488,190
Revenue, including existing Rider J ($000s)	74,021	74,353
Incremental 2023/24 GRA Revenues ($000s)	6,667	15,320
Total Revenues ($000s)	80,688	89,673

REFERENCE: Application, Sales and Generation – Overview, page 2-2
Non-firm secondary sales

QUESTION:

a) Although YEC states that no secondary sales were included in the 2021 GRA, there were secondary sales of 4.7 GWh in 2021 and 3.4 GWh in 2022. Please explain what YEC did with the amounts collected from secondary sales for each of the 2021 and 2022.

b) For each of the 2023 and 2024 test years, YEC forecasts secondary sales at 2.9 GWh. Please provide details of how YEC forecasted these amounts for each test year.

ANSWER:

(a)

The secondary sales revenues in 2022 and 2023 were included as part of YEC's revenues and used for YEC's operations, including reinvestment through capital projects.

(b)

The forecasts for the test years are prepared based on actual secondary sales experienced in 2022 and expected water conditions for 2023 and 2024 at the time of preparation of the GRA.

The actual secondary sales for 2023 were at 0.9 GWh compared to 2.9 GWh forecast for the test year due to reduced hydro output [Mayo A outage, reduced Whitehorse output due to WH4 outage and spinning reserve requirements, and drier Aishihik conditions].

REFERENCE: **Application, Sales and Generation – Overview, pages 2-2 to 2-4**
YEC provides its rationale for various load forecasts and hydro forecasts, as well as forecast fuel amounts and costs. YEC states: "Accordingly, for the purpose of the 2023/24 GRA test years, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information."

QUESTION:

a) Please provide details of how YEC determined the load amounts for the grid.

b) Given that YEC based the hydro generation forecasts on LTA water supply, please explain which forecasting model was used and how YEC determined these forecasts using this model.

c) Please provide a schedule demonstrating the forecasted results, for both hydro and thermal generation, from the model used and the actual amounts of generation for each the last 10 years.

d) Please explain if and when each forecasting model was tested and approved by the regulator.

e) If any of these forecasting models have not been adequately tested, is YEC prepared to do so in this GRA process?

ANSWER:

(a)

Please see details of sales forecasts in Section 2.2 and generation forecasts in Section 2.3 of the Application.

- The wholesale forecasts for 2023 and 2024 are prepared based on multi-variate regression assessments of monthly wholesales changes, the same approach used in the 2021 GRA, at normal weather conditions using the 20-year historical averages.

- The industrial sales forecasts for Victoria Gold and Hecla Yukon (previously Alexco) are based on information provided by the customers.

- Residential sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities. The forecast growth in 2023 and 2024 is also consistent with the population growth projections by the Yukon Government and the City of Whitehorse projections.

- General Service sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities plus separate forecasts for two large general service customers: Faro Mine remediation project and Minto Mine care and maintenance load.

The generation forecast is based on sales plus 8.8% line losses which is the same as the 2021 GRA approved level and also within the range of historical losses for the last three years [2020 at 9.1%, 2021 at 8.4% and 2022 at 9.0%].

(b), (d) and (e)

YEC used the YECSIM model to determine long-term average hydro and thermal generation volumes. The details are provided in Appendix 2.1.

The same model was used in the previous GRAs [2012/13 GRA, 2017/18 GRA and 2021 GRA] and the Board approved the revenue requirements based on long-term averages determined using the YECSIM model. YEC used the same model to determine the 2023 and 2024 long-term averages with updates to reflect new information affecting specific elements of the hydro grid as detailed in Appendix 2.1, page 2.1-1.

The model was subject to an extensive review by the Board and Intervenors, including in the 2017/18 GRA as well as in the two-part Energy Reconciliation Adjustment ("ERA") application review process that included a workshop on the YECSIM model.

(c)

Long-term average hydro model estimates using any water model (including YECSIM) are not structured in a way that lends to retrospective verification and does not replicate or reconcile to the actual past short-term operational decisions. The long-term averages are based on historical water year records and operational rules for each hydro facility and reservoir, while the actuals are impacted by output from the hydro facilities based on water conditions and operational decisions. In short, the LTA thermal and hydro generation forecast for each GRA has no relevance or relationship to actual thermal or hydro generation required in each test year under actual hydro availability conditions.

The Low Water Reserve Fund (LWRF) addresses, after each fiscal year-end, any variance between actual thermal generation and long-term average requirements caused by variations in water supply for hydro generation facilities and availability of other renewable sources.

The following table shows annual LWRF [previously DCF] transfers for the last 10 years:

- When the actual thermal is lower than the long-term average thermal, then YEC transfers to LWRF.

- When the actual thermal is higher than the long-term average thermal, then YEC withdraws from LWRF.

		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
A	YEC Grid load net of expected Fish Lake/Wind/IPPs, GWh	423.3	418.2	397.8	410.5	411.8	446.4	447.2	437.2	501.4	529.4	532.7
B	LTA thermal, GWh	15.6	13.3	5.3	10.0	10.5	13.3	16.4	25.3	67.4	78.3	78.6
C	Actual thermal net of capital/RFID/maintenance, GWh	2.7	1.0	0.6	2.8	5.1	13.3	18.7	68.2	69.4	39.6	39.2
D=C-B	Variance to be included in the LWRF, GWh	-12.9	-12.3	-4.7	-7.2	-5.4	0.0	2.4	42.9	1.9	-39.7	-38.4
E=A-B	LTA hydro for LWRF calculation purposes, GWh	407.7	405.0	392.5	400.5	401.3	433.2	430.8	411.9	434.0	451.1	454.0
F=A-C	Assumed actual hydro for LWRF calculations purposes, GWh	420.6	417.2	397.2	407.7	406.8	433.2	428.4	369.0	432.1	489.8	493.5
G	Actual hydro net of secondary sales related generation, GWh	421.0	417.0	394.6	404.8	406.2	432.0	412.8	370.8	435.4	488.1	488.4

Note: Assumed actual hydro for LWRF calculations purposes takes net grid load in line A less actual thermal net of capital/RFID/maintenance in line C [i.e., it assumes absent the thermal for capital/RFID/maintenance, the actual hydro would be at that level].

REFERENCE: Application, Sales and Generation – Overview, pages 2-2 to 2-4
Peak load forecasts, excluding industrial load

QUESTION:

a) Since the industrial load is not considered for the N-1 peak load criteria, explain how industrial peak load is managed.

b) Please explain whether and how the mines contribute to the costs and amounts of fuel used with the rented diesels for peak load requirements.

ANSWER:

(a)

The N-1 standard does not include industrial loads as part of the assessment as major industrial customers typically maintain sufficient on-site generation for their own emergency purposes.

(b)

Although the N-1 standard does not include industrial peak, industrial customers currently share the diesel rental costs as part of the overall rate increase, as well as any fuel used for the rental units [for rate setting purposes, YEC does not distinguish the diesel fuel cost between own units and rental units].

REFERENCE: Application, Sales and Generation – Overview, Sales Forecast, page 2-4

QUESTION:

a) In the summary on page 2-4, lines 11-14, please explain why YEC has not included secondary sales in this forecasting.

b) For Wholesale sales to ATCO, YEC proposes to forecast these amounts "based on multi-variate regression assessments of monthly wholesale changes". Please provide an explanation of this forecasting method using examples.

c) YEC continues to provide rationale for not following directions from Board Order 2022-03 "to align YEC wholesale sales forecasts". Please provide a schedule showing each sales forecast for YEC and for ATCO for the last 10 years as well as forecasted 2023 and 2024.

d) Please provide a schedule showing the 2023 and 2024 wholesale sales forecast by YEC and the actual wholesale sales for the prior 10 years.

ANSWER:

(a)

The referenced lines reflect primary firm wholesale sales forecasts.

The secondary sales forecasts are provided in Section 2.2.4 of the Application. The secondary sale has a separate rate schedule and rates.

(b)

The multi-variate regression assessment uses the 20-year monthly sales data to determine multi-variate regression coefficients that are then used for wholesale sales forecasts based on average temperatures. It includes average temperatures, heating degree days, cooling degree days, days with average temperature lower than 20 degrees, darkness hours, no work days and customer counts.

The predicted wholesale forecast is then adjusted for long-term average Fish Lake generation and forecast microgen generation [forecast microgen generation reduces the load in two ways: reduced grid load consumption by a customer who owns microgen and the amount put back into the grid].

The following table shows the example of wholesale forecast for 2023 [GWh]:

Multivariate Restults	Microgen	LTA Fish Lake	Estimated DSM	Wholesale Forecast
A	B	C	D	E=A-B-C-D
369.1	8.2	8.7	0.9	351.3

The multivariate linear regression model results also validate the forecast based on professional judgment. For example, as reviewed in response to d) below, the forecast wholesales for 2023 at 351.3 GWh is about 1.4% higher than the 2022 actual wholesales and within the annual average change over the last 10 years.

(c)

YEC did follow the directions from Board Order 2022-03 to work with AEY regarding the wholesale sales forecasts. As indicated in Section 2.2.1 of the Application, YEC reached out to the AEY Regulatory team and provided updates regarding YEC's GRA wholesale forecast. YEC and AEY staff worked to understand forecasting methodology and inputs into their respective forecasts. However, each company decided to proceed with its respective forecasts for 2023 and 2024 in the GRAs that have been filed.

Please see the response to YUB-YEC-1-9 for further details.

(d)

Please see the table below.

	Firm Wholesales, GWh	Annual Change
2012	310.3	
2013	307.9	-0.8%
2014	295.3	-4.1%
2015	298.0	0.9%
2016	301.2	1.1%
2017	328.4	9.0%
2018	332.3	1.2%
2019	331.5	-0.2%
2020	347.3	4.8%
2021	349.0	0.5%
2022	346.3	-0.8%
Average annual		1.1%
2023F	351.3	1.4%
2024F	355.9	1.3%

REFERENCE: **Application, Sales and Generation – Overview, Major Industrial, page 2-5**

"Minto Mine included as industrial customer for Jan.-May/2023 and for June-Dec. 2023 and 2024 the load for Minto care and maintenance is included under the general service class."

QUESTION:

a) Please provide details of the consumption and related dollar amounts for each of these proposals including actuals and forecasted.

b) Please explain how and if the amount from January to May 2023 was actually collected from Minto.

c) Please provide details of how much Minto owed YEC upon stopping operations.

d) Please explain how YEC is proposing to recover any outstanding amounts owed.

ANSWER:

(a)

Please see the table below for forecast amounts included in the GRA.

Description	GRA Forecast 2023 Forecast	GRA Forecast 2024 Forecast
Minto Mine - Industrial		
Sales in MWh	16,389	0
Existing Rate Revenue, including Rider J ($000s)	2,530	0
Minto Mine Care and Maintenance - General Service		
Sales in MWh	8,022	13,103
Existing Rate Revenue, including Rider J ($000s)	1,624	2,656

The actual sales under the industrial rate class for 2023 were at 16.4 GWh with $2.5 million in revenues, including existing Rider J.

The full-year-forecast sales under the general service class for 2023 are expected to be about 9.2 GWh with about $1.9 million in revenues, including existing Rider J.

Yukon government notes that “as a regulator, the Yukon government’s focus is ensuring that the environment remains protected at the Minto mine site” and it holds financial security for the site and intends to access this funding to cover the costs of the reclamation work. Currently, all electricity bills are calculated under Rate Schedule 2180, General Service Hydro, Government – Federal & Territorial and sent directly to Yukon government.

(b)

As of today, the sales to Minto as an Industrial customer from January to May 2023 have not been collected.

(c)

The total billings to Minto that accrued to when they stopped operating as an Industrial customer is $4.015 million.

(d)

YEC has actively participated in Minto’s receivership court proceedings. Currently, the Receiver is attempting to sell the mine and YEC is actively following the process. The ultimate amount YEC collects is dependent on several factors, including whether the mine is sold in its entirety. If the mine is not sold, the Receiver will continue with an asset sale, of which YEC will be entitled to a portion of those proceeds. YEC will provide an update to the YUB regarding the amount recovered.

REFERENCE: **Application, Sales and Generation – Overview, Major Industrial, page 2-6**

"Hecla Yukon (previously Alexco) resumed industrial operations in late 2020 in the Keno region north of Mayo and east of the Eagle Gold mine."

QUESTION:

a) Please explain how Hecla remains under the same sales agreement with YEC as to what was a regulated process with Alexco.

ANSWER:

(a)

Hecla acquired Alexco Resource Corp. on July 5, 2022.

REFERENCE: **Application, Sales and Generation – Overview, Power Generation, page 2-9**

"The proposed forecast LTA YEC hydro generation for 2023 is 444.9 GWh and for 2024 is 446.2 GWh, utilizing updates to the LTA forecast (see Section 2.3.2)."

QUESTION:

a) Please provide an explanation for how section 2.3.2 of the application explains this hydro generation forecast.

b) Please provide detailed descriptions of how these forecasts were determined for each of the test years.

c) Please provide descriptions of which forecast model was used for this determination.

d) Please provide a schedule showing forecast hydro generation and actual generation figures for past 10 years.

ANSWER:

(a) to (c)

Please see the response to UCG-YEC-1-19 (b), (d), and (e).

(d)

Please see the response to UCG-YEC-1-19 (c).

REFERENCE: **Application, Sales and Generation – Overview, Power Generation, page 2-10**

Integrated Grid Hydro Generation
"In Yukon, seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but not at Whitehorse."

QUESTION:

a) Please explain why Whitehorse #4 is not considered seasonal storage.

ANSWER:

(a)

Whitehorse Rapids is a run-of-the-river plant. As such, there is no ability to store water at this facility as would be required to provide for seasonal storage.

REFERENCE: Application, Sales and Generation – Overview, Power Generation, page 2-10 Diesel and LNG

QUESTION:

a) Please explain how forecast grid load is determined.

b) In Tables 2.1-1 and 2.1-2 in Appendix 2.1, does the line number indicate the water year or where is this indicated?

c) Please explain which forecast model was used to determine the values in Tables 2.1-1 and 2.1.2 and provide details of the forecast methodology used.

d) Please explain how LTA thermal generation was determined before the new forecasting model being used.

e) Please provide a schedule indicating LTA forecast diesel and LNG thermal generation and actual diesel and LNG thermal generation for the last 10 years.

ANSWER:

(a)

Please see the response to UCG-YEC-1-19 (a).

(b)

No. The line numbers do not indicate the water years. The values in the tables are based on averages of results for 41 water years [1981-2021], i.e., long-term averages.

(c)

Please see the response to UCG-YEC-1-19 (b), (d) and (e).

(d)

As indicated in the response to UCG-YEC-1-19 (b), (d) and (e), the YECSIM model has been used since the 2012/13 GRA to determine long-term hydro generation, including in 2017/18 GRA and 2021 GRA and now in the 2023/24 GRA. The long-term thermal generation is calculated as total firm grid load less long-term average hydro and other renewable resources.

Before the 2012/13 GRA, YEC's last GRA was with the 2008 and 2009 test year when WAF and MD systems were not connected and long-term average hydro generations were estimated separately for WAF [Whitehorse and Aishihik hydro facilities] and MD [Mayo hydro facility]. YEC's 2009 GRA, pages 2-11 and 2-12 noted that the WAF long-term average was 351 GWh[1] which assumed Faro mine is connected and all available hydro units are fully utilized and for MD it was approximately 40 GWh. The diesel generation was only about 0.3%-0.4% of the total load for the 2008 and 2009 test years.

(e)

Please see the response to UCG-YEC-1-19 (c).

[1] Based on YEC's 2006 20-Year Resource Plan, Whitehorse hydro units (40 MW capacity) on a long-term basis were expected to generate about 246 GW.h/year, implying average annual operation at about 70% of annual capacity and 105 GWh for Aishihik hydro facility.

REFERENCE: Application, Sales and Generation – Overview, Power Generation, page 2-12 Peak Demand Forecast

QUESTION:

a) Please explain details of the forecasting model used to determine peak loads and the methodology this model uses.

b) Provide a schedule chart giving forecast peak demand (separating non-industrials and industrial peak load) and actual peak demand (separating non-industrials and industrials) for last 10 years.

c) Please explain how the mines (industrials) are accounted for in the peak demand costs.

d) Please explain how the mines (industrials) are accommodated in the contingency peak demand as they are not included in the N-1 criteria (i.e., do they utilize their own on-site generation?).

e) Please explain how the costs associated with mine peak loads are recovered.

ANSWER:

(a)

The initial forecast was prepared by Itron in 2018 based on a -35 deg C design temperature (the coldest average temperature in Whitehorse in the last 10 years). In 2019, the long-term peak forecast design temperature was updated to -37 deg C based on the new record coldest day from January 2019. The current updated peak forecasts use -39 deg C based on the new coldest day record from January 2022.

The Itron econometric model uses a range of input data, including historical sales and energy data by customer class, economic activity, population projections, electricity prices, and improvements in end-use efficiency and standards, and system design temperature to produce a long-term peak forecast. The model also takes into account the impact of Yukon's strategy for climate change, energy and a green economy, particularly as regards future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

Industrial peak loads are based on information provided by the customers.

(b)

Please see the table below that shows the actual peak for 2013-2022 years. The table also includes the forecast total peak included in 2012/13, 2017/18 and 2021 GRAs.

	Total Peak, MW	Industrial Peak, MW	Non-Industrial Peak, MW	Total Peak forecast in the GRAs, MW
2013	72.0	3.7	68.3	81.1
2014	77.7	4.3	73.4	
2015	83.7	4.1	79.6	
2016	88.1	5.5	82.5	
2017	92.6	6.3	86.3	91.8
2018	93.0	6.6	86.4	92.9
2019	90.9	2.1	88.8	
2020	103.8	6.2	97.7	
2021	104.4	12.8	91.6	112.7
2022	114.2	9.5	104.7	

(c) and (e)

The capacity shortfall and related rental diesel costs for the 2023 and 2024 test years are determined based on the N-1 criterion which excludes the industrial peak. There is no separate incremental cost in the test years that are specifically related to the industrial peak.

The industrial customers pay demand charges which are then used as existing rate revenue in the determination of revenue shortfalls and rate calculations.

Please also see the response to UCG-YEC-1-20 (b).

(d)

Please see the response to UCG-YEC-1-20 (a).

REFERENCE: **Application, Sales and Generation – Overview, Power Generation, page 2-17**

Peak Demand Forecast - Table 2.2, line 3, Losses %

QUESTION:

a) Please explain how line losses are forecasted to increase from 2021.

b) Please explain what YEC has done to lower these line losses since the last GRA.

ANSWER:

(a)

Line losses of 8.8% is the historical average. Variations in line losses are dependent upon how we use our generation assets. For example, adding or running more Whitehorse generation lowers average system losses. In addition, losses are not limited to just lines. What we call line loss are all losses between the generator to YEC customers or generators to ATCO distribution points. Therefore, losses include:

- Transmission lines;
- Transmission transformers;
- YEC distribution lines and transformers;
- YEC distribution power theft;
- Generation station power heat etc.;
- LNG power to maintain system cooling;
- Transmission substation power;
- Whitehorse trash rack heat.

(b)

As described in part (a), which generation assets are used has an impact on the average line losses. The farther generation is from the demand the larger the losses. Yukon Energy has focused on maintenance of the system rather than changes to the transmission lines to lower line losses. However, YEC considers a reduction in line losses as an option if the business case supports it. On the transmission side, the largest amount

of line losses are coming from the Aishihik to Whitehorse transfer. In the current Resource Plan update, YEC will consider twinning the transmission line between Aishihik and Whitehorse to reduce line losses by approximately 50% (for this section), but current estimated costs are approximately $100 million.

REFERENCE: Application, Table 3-1: Yukon Energy Revenue Requirement

QUESTION:

a) Please provide a table similar to Table 3.1 showing YUB-approved revenue requirement components and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column and include footnotes identifying the YUB orders that approved the revenue requirements.

b) Please provide a table similar to Table 3.2 showing YUB-approved fuel and purchased power costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

c) Please provide a table similar to Table 3.3 showing YUB-approved non-fuel O&M expenses and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

d) Please provide a table similar to Table 3.4 showing YUB-approved employee complement and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

e) Please provide a table similar to Table 3.4.1 showing explanations for all employee complement between approved and actual for 2017, 2018, 2019, 2020, 2021 and 2022.

f) Please provide a table similar to Table 3.5 showing YUB-approved production costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

g) Please provide a table similar to Table 3.6 showing YUB-approved transmission and distribution costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

h) Please provide a table similar to Table 3.6.1 showing YUB-approved brushing costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

i) Please provide a table similar to Table 3.7.1 showing YUB-approved transmission costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

j) Please provide a table similar to Table 3.7.2 showing YUB-approved distribution costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

k) Please provide a table similar to Table 3.8 showing YUB-approved general O&M costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

l) Please provide a table similar to Table 3.9 showing YUB-approved administration costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

m) Please provide a table similar to Table 3.10 showing YUB-approved insurance and reserve for injuries and damages costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

n) Please provide a table similar to Table 3.12 showing YUB-approved property taxes costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

o) Please provide a table similar to Table 3.13 showing YUB-approved rate base components and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

p) Please provide a table similar to Table 3.14 showing YUB-approved depreciation and amortization costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

q) Please provide a table similar to Table 3.14.1 showing YUB-approved Hearing Cost Reserve Account balances / transactions and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

r) Please provide a table similar to Table 3.14.2 showing YUB-approved Deferred Vegetation Management costs and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

s) Please provide a table similar to Table 3.14.3 showing YUB-approved Reserve for Site Restoration Account balances / transactions and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

t) Please provide a table similar to Table 3.14.4 showing YUB-approved Defined Pension Deferral Account balances / transactions and actuals for 2017, 2018, 2019, 2020, 2021 and 2022. Please identify percentage changes from column to column.

u) Please provide a table similar to Table 3.15 showing YUB-approved cost of capital and actuals for 2017, 2018, 2019, 2020, 2021 and 2022.

ANSWER:

(a) to (u)

Please see UCG-YEC-1-29 Attachment 1 that shows approved and actuals for 2017, 2018 and 2021 years. There are no approved amounts for the 2019, 2020 and 2022 years as there was no GRA during these periods.

The defined pension deferral account only came into existence during the 2021 GRA, hence there is no information for prior years for Table 3.14.4.

Table 3.4.1 relating to employee complement changes is a specific analysis of changes since the 2021 GRA, and as such cannot be addressed under this IRs requirement. Table 3.4 adequately provides details of the approved and actual employee complement history.

Table 3.1
Yukon Energy Revenue Requirement
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Fuel and Purchased Power	$ 2,460	$ 2,460	0.0%	$ 2,677	$ 5,348	99.8%	$ 15,882	$ 12,667	-20.2%
Non-Fuel Operating and Maintenance	22,452	22,476	0.1%	22,125	23,497	6.2%	28,575	28,667	0.3%
Depreciation and Amortization	10,848	10,848	0.0%	11,141	11,104	-0.3%	12,631	13,692	8.4%
Return on Rate Base	13,442	13,584	1.1%	13,850	12,110	-12.6%	16,161	16,448	1.8%
Revenue Requirement/Revenue	$ 49,202	$ 49,367	0.34%	$ 49,794	$ 52,059	4.55%	$ 73,249	$ 71,473	-2.42%

Table 3.2
Fuel and Purchased Power
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Fuel	2,411	2,411	0%	$ 2,638	$ 5,295	101%	$ 15,829	$ 12,618	-20%
Purchased Power	49	49	0%	39	53	35%	53	49	-7%
Total Fuel and Purchased Power	$ 2,460	$ 2,460	0%	$ 2,677	$ 5,348	100%	$ 15,882	$ 12,667	-20%

Note:

1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance requirements, and forecast fuel prices.

Table 3.3
Non-Fuel Operating and Maintenance Expenses
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 11,869	$ 11,893	0.2%	$ 11,932	$12,083	1.3%	$ 13,016	$ 13,167	1.2%
Production	2,190	2,194	0.2%	1,799	3,300	83.4%	5,636	5,285	-6.2%
Transmission	1,448	1,446	-0.2%	1,419	1,058	-25.4%	1,394	1,387	-0.5%
Distribution	571	568	-0.4%	535	449	-16.1%	491	399	-18.7%
General O&M	1,306	1,306	0.0%	1,219	1,395	14.4%	1,391	1,353	-2.7%
Administration	2,864	2,864	0.0%	3,001	3,016	0.5%	3,858	4,170	8.1%
Insurance and Reserve for Injuries/Damages	1,511	1,511	0.0%	1,510	1,525	1.0%	2,039	2,166	6.2%
Property Taxes	693	693	0.0%	708	671	-5.3%	750	739	-1.4%
Total OM&A (Tab 7, Schedule 10)	$ 22,452	$ 22,476	0.1%	$ 22,125	$23,497	6.2%	$ 28,575	$ 28,667	0.3%

Table 3.4
Employee Complement History

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
President & Corporate Services	4.12	4.12	0%	4.16	5.14	24%	4.16	4.07	-2%
Government Relations	-	-		-	-		1.00	1.00	0%
Business Development	-	-		-	-				
Communications & Customer Service	1.00	1.00	0%	1.00	1.00	0%	3.60	3.60	0%
People & Culture	5.21	5.21	0%	5.25	5.27	0%	1.00	1.00	0%
Resource Planning, Environment, Health & Safety	7.00	7.00	0%	7.00	7.00	0%	8.05	8.04	0%
Finance, Procurement & IT	16.94	16.94	0%	16.79	16.89	1%	19.04	19.10	0%
Operations	44.12	44.12	0%	44.50	46.58	5%	48.25	49.89	3%
Engineering Services	16.00	16.00	0%	15.00	13.03	-13%	15.50	15.16	-2%
Total	94.39	94.39	0%	93.70	94.91	1%	100.60	101.86	1%

Note:
1. The employee complement numbers are net of allocation to YDC.

Table 3.5
Production Costs
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 4,176	$ 4,200	0.6%	$ 4,131	$ 4,455	8%	$ 4,802	$ 5,076	6%
Diesel	693	693	0.0%	425	1,617	280.2%	4,028	4,113	2%
LNG	181	181	0.0%	196	357	81.8%	410	85	-79%
Hydro	1,209	1,209	0.0%	1,093	1,229	12.5%	1,082	941	-13%
Wind	40	40	0.0%	6	-35	-725%	0	0	0%
Operation Supervision	66	71	7.0%	79	132	67%	116	146	25%
Total Production	$ 6,366	$ 6,394	0%	$ 5,930	$ 7,755	31%	$ 10,438	$ 10,360	-1%

Table 3.6
Transmission and Distribution Costs
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 1,516	$ 1,516	0%	$ 1,490	$ 1,328	-11%	$ 1,303	$ 1,346	3%
Brushing Cost	1,454	1,454	0%	1,492	1,134	-24%	1,388	1,313	-5%
Other Non-Labour	565	565	0%	463	373	-19%	498	474	-5%
Total T&D	$ 3,535	$ 3,535	0%	$ 3,445	$ 2,835	-18%	$ 3,188	$ 3,133	-2%

Table 3.6.1
Brushing Costs
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Transmission Brushing	$ 1,134	$ 1,134	0%	$ 1,161	$ 922	-21%	$ 1,175	$ 1,197	2%
Distribution Brushing	320	320	0%	331	212	-36%	212	116	-45%
% Transmission	78%	78%		78%	81%		85%	91%	
% Distribution	22%	22%		22%	19%		15%	9%	
Total Brushing Expense	$ 1,454	$ 1,454	0%	$ 1,492	$ 1,134	-24%	$ 1,388	$ 1,313	-5%

Table 3.7.1
Transmission Costs
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 655	$ 655	0%	$ 635	$ 526	-17%	$ 674	$ 645	-4%
Brushing Cost	1,134	1,134	0%	1,161	922	-21%	1,175	1,197	2%
Other Non-Labour	315	315	0%	258	136	-47%	219	190	-13%
Total Transmission	$ 2,104	$ 2,104	0%	$ 2,054	$ 1,585	-23%	$ 2,068	$ 2,032	-2%

Table 3.7.2
Distribution Costs
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 861	$ 861	0%	$ 856	$ 801	-6%	$ 629	$ 701	11%
Brushing Cost	320	320	0%	331	212	-36%	212	116	-45%
Other Non-Labour	251	251	0%	204	236	16%	279	283	2%
Total Distribution	$ 1,431	$ 1,431	0%	$ 1,391	$ 1,250	-10%	$ 1,120	$ 1,101	-2%

Table 3.8
General Operating and Maintenance
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 466	$ 466	0%	$ 395	$ 351	-11%	$ 372	$ 275	-26%
Transportation	540	540	0%	504	553	10%	555	521	-6%
Maintenance of Company Owned Properties	593	593	0%	508	667	31%	598	665	11%
SCADA Communication	173	173	0%	207	176	-15%	238	167	-30%
Total General O&M	$ 1,772	$ 1,772	0%	$ 1,615	$ 1,746	8%	$ 1,763	$ 1,628	-8%

Table 3.9
Administration
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Labour	$ 5,711	$ 5,711	0%	$ 5,916	$ 5,949	1%	$ 6,539	$ 6,471	-1%
Resource Planning	15	15	0%	48	48	0%	84	93	10%
Communications	130	129	0%	130	126	-3%	155	134	-14%
Customer Accounting	203	203	0%	225	208	-7%	240	202	-16%
Environmental Mgmt	252	252	0%	238	184	-23%	535	392	-27%
General	661	657	-1%	662	688	4%	790	967	22%
Information Systems	654	654	0%	645	555	-14%	741	1,048	41%
Fish Hatchery	183	183	0%	168	158	-6%	210	240	14%
Safety	170	156	-8%	182	210	15%	226	185	-18%
Training	140	140	0%	175	173	-1%	200	121	-39%
Recruitment	222	170	-23%	229	245	7%	255	149	-42%
Board of Directors	158	158	0%	182	246	35%	252	305	21%
Union	0	52		20	119	496%	90	316	251%
Regulatory Affairs	29	30	1%	33	26	-20%	20	11	-43%
Material Management	32	32	-1%	37	9	-76%	32	-7	-123%
Contracting	14	14	0%	12	5	-55%	12	2	-83%
Professional Development	0	2		15	15	2%	15	12	-21%
Total Administration	$ 8,575	$ 8,559	-0.2%	$ 8,917	$ 8,966	0.5%	$ 10,397	$ 10,641	2.3%

Table 3.10
Insurance and Reserve for Injuries & Damages
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Insurance	$ 1,032	$ 1,032	0%	$ 1,031	$ 1,046	1%	$ 1,423	$ 1,550	9%
Reserve Appropriation (RFID)	479	479	0%	479	479	0%	616	616	0%
Total	$ 1,511	$ 1,511	0%	$ 1,510	$ 1,525	1%	$ 2,039	$ 2,166	6%

Table 3.12
Property Taxes
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Property Taxes	$ 693	$ 693	0%	$ 708	$ 671	-5%	$ 750	$ 739	-1%

Table 3.13
Mid-Year Net Rate Base
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Mid-Year:									
Net plant in service	$ 277,808	$ 277,808	0%	$ 278,702	$ 287,713	3%	$ -	$ -	
Before contributions	$ 435,392	$ 435,392	0%	$ 445,367	$ 449,441	1%	$ 484,926	$ 470,798	-3%
Less contributions	170,785	170,785	0%	167,112	166,677	0%	182,552	176,771	-3%
Net plant in service	264,607	264,607	0%	278,255	282,764	2%	302,374	294,027	-3%
Mid-year regulatory deferral	3,034	3,034	0%	3,879	3,805	-2%			
Working capital	5,290	5,290	0%	5,344	5,617	5%	7,092	6,925	-2%
Net Rate Base	$ 272,931	$ 272,931	0%	$ 287,478	$ 292,186	2%	$ 309,466	$ 300,951	-3%

Table 3.14
Depreciation and Amortization
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Fixed Asset Depreciation	$ 12,323	$ 12,323	0.0%	$ 12,196	$12,185	-0.1%	$ 13,436	$ 14,927	11.1%
Less: Contributions	-5,539	-5,539	0.0%	-5,652	-5,635	-0.3%	-5,912	-6,085	2.9%
Less: Amortization of fire insurance recoveries	-262	-262	0.0%	-262	-262	0.0%	-262	-262	0.0%
Less: Disallowed Depreciation	-182	-182	0.0%	-204	-204	0.0%	-238	-416	74.7%
Plus: Amortization of deferred charges	4,507	4,507	0.0%	5,063	5,020	-0.9%	5,608	5,529	-1.4%
Total Depreciation & Amortization	$ 10,848	$ 10,848	0.0%	$ 11,141	$11,104	-0.3%	$ 12,631	$ 13,692	8.4%

Table 3.14.1
Hearing Cost Reserve Account Continuity Schedule
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Opening Balance	-$973	-$973	0%	-$1,026	-$1,026	0%	$63	$182	188%
Annual Appropriation	-55	-55	0%	-55	-55	0%	-55	-55	0%
Annual Costs	3	3	0%	155	155	0%	0	101	
Closing Balance	-$1,026	-$1,026	0%	-$926	-$926	0%	$8	$227	2819%

Notes:

1. As per Board Order 2018-10, the Hearing Cost Reserve Account reflects the annual appropriation of $0.250 million plus amortization of the 2016 credit balance over a five-year period [$0.195 million/year] to the total of $0.055 million for 2017-2021 years. The annual appropriation for 2022 actual, and 2023 and 2024 test years at $0.250 million.

2. The Proposed 2024 column does not include 2023/24 GRA hearing related costs as the costs are included in the hearing reserve after approval by the YUB and YEC does not expect the 2023/24 GRA hearing costs will be approved by end of 2024.

Table 3.14.2
Deferred Vegetation Management Continuity Schedule
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Opening Balance	$2,215	$2,215	0%	$1,994	$1,994	0%	$1,329	$1,329	0%
Annual Deferred Costs	0	0	0%	0	0	0%	0	0	0%
Annual Amortization	-222	-222	0%	-222	-222	0%	-222	-222	0%
Closing Balance	$ 1,994	$ 1,994	0%	$ 1,772	$ 1,772	0%	$ 1,108	$ 1,108	$ 0

Table 3.14.3
Reserve for Site Restoration Continuity Schedule
($000)

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Opening Balance	$4,359	$4,359	0%	$4,304	$4,303	0%	$2,790	$2,738	-2%
Annual Appropriation	0	0	0%	0	0	0%	0	0	0%
Annual Costs	-55	-55	0%	-165	-340	106%	0	0	0%
Closing Balance	$ 4,304	$ 4,303	0%	$ 4,139	$ 3,963	-4%	$ 2,790	$ 2,738	-2%

Table 3.15
Cost of Capital

	Approved 2017	Actual 2017	% Change	Approved 2018	Actual 2018	% Change	Approved 2021	Actual 2021	% Change
Average Cost of Debt	2.40%	2.58%	7.67%	2.23%	2.58%	15.94%	2.94%	2.93%	-0.09%
Return on Equity	8.70%	8.72%	0.22%	8.70%	6.25%	-28.17%	8.65%	8.93%	3.24%
Average Cost of Capital	4.92%	5.14%	4.37%	4.82%	4.14%	-13.97%	5.22%	5.42%	3.71%

REFERENCE: **Application, Tab 5-3 – Deferred Costs, page 5-10**

"Deferred costs additions to rate base net of contributions approximated $0.854 million during 2021 and $4.545 million during 2022, and are forecast at approximately $12.644 million during 2023 and $2.728 million during 2024 (total of approximately $16.5 million over these years - see Table 5.6).

Deferred expenditures in WIP during 2021 through 2024, and not affecting rate base until after 2024, are forecast in total at approximately $28.9 million (see Table 5.7)."

QUESTION:

a) Please explain in detail (including associated references) if the approximated amount in deferred cost additions during 2021 and 2022 which was placed into rate base was the same as allowed in the 2021/22 GRA process.

b) Please explain the significant difference between 2022 and the forecasted 2023 test year.

c) Please explain the difference between deferred cost additions to rate base and deferred expenditures in WIP referenced and explain what needs to happen before deferred expenditures in WIP become additions to rate base.

d) Please provide an explanation of the difference between the 2024 deferred costs referenced and the differed expenditures in WIP.

ANSWER:

(a)

2022 rate base additions were not assessed by the Board during the 2021 GRA, and were not included in 2021 GRA approved rates. Actual 2022 rate base additions are noted below, based on Table 5.5 of the Application.

Explanation for 2021 rate base additions are as follows (reference: Appendix A to Board Order 2022-03, pages 67-68):

- DSM program development - $10,379 added to 2021 rate base, $85,000 allowed by YUB; 2022 new rate base additions approximated $353,400;

- IPP Standing Offer Program Implementation - $325,998 added to rate base, $330,057 allowed by YUB; no 2022 new rate base additions;

- Dam Safety Review – $254,489 added to rate base, $253,600 allowed by YUB; no 2022 new rate base additions;

- Other Projects with <$100k Spending - $262,769 added to rate base, these projects are not reviewed by the YUB on project by project basis.

(b)

The most significant difference in rate base additions between 2022 actual and 2023 forecast is the Southern Lakes Storage project being closed and adding a cost of $8.784M (absent this addition, 2023 deferred costs for projects > $1 million is $2.0 million or less than 50% of the equivalent 2022 actual rate base additions).

(c)

Costs incurred for deferred projects remain in WIP until the project is completed, at which time the costs are added to rate base (also see response to YUB-YEC-1-63).

(d)

During 2024, total spending on deferred projects is $10.37M ($1.16M and $0.865 from Table 5.5 and $7.71M and $0.635M from Table 5.7). Total added to rate base is $2.478M (from Table 5.5) which includes spending from 2024 as well as from prior years.

REFERENCE: **Application, Tab 5-3 – Deferred Costs, page 5-10**
Major Deferred Projects >$1 Million – Rate Base Additions

"Aishihik Relicensing (Five Year Licence Renewal) - ($3.903 million expenditure in 2022 and $0.575 million in 2023, with $4.479 million net increase in rate base by the end of 2023, excluding reductions due to amortization)."

"Demand Side (DSM) Program Development and DSM Program 2022-2030 – ($2.774 million net increase in rate base by the end of 2024, after contributions of $1.163 million but excluding reductions due to amortization)."

"Southern Lakes Storage ($8.784 million addition to rate base at the end of 2023, excluding reductions due to amortization)."

QUESTION:

a) Please provide a schedule showing all Aishihik relicensing costs by year incurred (including the 5 year license and short-term license).

b) Please explain if the 2022 Aishihik relicensing costs were included in the last rate hearing for that year it was costed. If not, why not?

c) Please provide a schedule outlining DSM costs for each year from 2022 through 2024, breaking down program development costs and DSM program costs.

d) Please explain why the 2022 costs for DSM were not included in last rate hearing.

e) Please provide a brief description of each DSM program for each year 2022 through 2024.

f) Please provide a schedule showing a breakdown by year of costs for the Southern Lakes Storage project.

g) If there are years prior to and including 2022 in the above Southern Lakes Storage project amounts, explain why this was not added to rate base in the 2021/22 GRA.

h) Please provide details (by year) of all costs incurred for the Southern Lakes Storage and Southern Lakes Enhancement (predecessor) projects from inception to today.

ANSWER:

(a)

Please see the table below.

Year	Spending
2015	50,149.39
2016	954,936.82
2017	1,969,163.68
2018	1,982,948.89
2019	512,754.81
2020	2,269,595.75
2021	1,273,065.23
2022	1,313,357.01
2023	792,449.10
Total	11,118,420.68

(b)

2022 Aishihik Relicensing costs were not included in the 2021 General Rate Application (the 2021 GRA did not include forecast 2022 costs).

(c)

Please see the table below.

	2022	2023	2024
DSM Program	64,222	1,271,641	1,160,000
DSM Program Development (Net)	143,719	- 21,641	-
Total	207,941	1,250,000	1,160,000

(d)

The 2021 GRA only included one test year (2021). As such, costs for 2022 were not included in that GRA for Board approval.

(e)

Please see Appendix 5.2A. Section 1.2 which reviews the DSM Program from 2022-2030; and Section 2.0 reviews the Detailed DSM Program 2022-2030 Business Plan. Section 2.1 provides an overview of the DSM portfolio and notes the information below (2025 costs are not included in the 2023-2024 GRA):

Phase 1: Fall 2022 to Fall 2024

1. **Residential Demand Response**: This program seeks to reduce the peak load contribution from space and water heating. It consists of a direct-install initiative wherein participants receive internet connected hot water tank controllers and/or thermostats, managed by Yukon Energy through a demand-response management system.

Phase 2: Fall 2024 to Fall 2025

1. **Residential Demand Response**: This program will transition from a direct-install initiative to a "bring your-own-device" program in Fall 2024, with annual incentives offered to participants by YEC.

2. **Dual Fuel Demand Management**: This program seeks to avoid the use of resistance heating as a backup heat source to air-source heat pumps at extreme cold temperatures. It consists of a direct install initiative targeting Yukon homes with both air-source heat pumps and fossil-fuel heating systems. Participants receive internet-connected thermostats (provided, configured, and managed by Yukon Energy) to automatically switch from the heat pump to the fuel-burning system when the outdoor air temperature drops below a threshold.

(f)

Please see the table that follows.

Year	Spending
2009	447,167.00
2010	1,035,711.00
2011	1,748,029.00
2012	1,074,040.76
2013	623,470.17
2014	605,333.30
2015	983,000.47
2016	364,602.70
2017	286,934.02
2018	150,788.81
2019	374,888.83
2020	244,960.36
2021	561,100.94
2022	284,143.61
Total	8,784,170.97

(g)

The project was not completed or closed at the time of the 2021 GRA, and therefore remained in WIP. As such, no project costs were added to rate base during the 2021 GRA. It wasn't until November 2022 that YEC concluded there was no reasonable probability that the project would proceed.

(h)

This information was provided in the Application (see Table in Appendix 5.2A, page 5.2-31-). Details have also been provided in prior General Rate Applications.

A breakdown of costs by cost category for each year from project inception to today is outlined below. It is noted that costs cannot be broken down by year by cost category prior to 2012 due to the change in financial system that year.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Grand Total
Environmental assessment	3,297,844	382,680	304,074	760,079	199,138	101,086	922	988	746	303,147	63,900	5,414,604
Project management	369,545						3,199	29	429	57,032	98	430,332
Public consultation	70,593	47,231	69,271	24,521	1,760	25,199	202	212,583	68,213	28,683	40,000	588,255
Third Party Engineering	101,136		215									101,352
YEC costs	246,145	30,053	44,681	67,968	22,288	16,996	271	1,027				429,430
AFUDC	219,685	163,506	187,092	130,432	141,416	143,654	146,194	160,262	175,572	172,239	180,146	1,820,199
Grand Total	**4,304,948**	**623,470**	**605,333**	**983,000**	**364,603**	**286,934**	**150,789**	**374,889**	**244,960**	**561,101**	**284,144**	**8,784,171**

1

REFERENCE: Application, Tab 5-3 – Deferred Costs, pages 5-10 and 5-11

"Test year spending on major deferred cost projects focuses on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other future potential generation and transmission requirements."

"Feasibility Studies – Reliability & Asset Improvements. Rate base additions of approximately $2.229 million for the following projects:

- Whitehorse Post-Flood Assessment ($0.115 million in 2022);
- Mayo Civil Infrastructure Refurbishment Planning ($0.168 million in 2023);
- System Wide Arc Flash Study ($0.198 million in 2023);
- System Wide Stability Study ($0.200 million in 2023);
- Digital Strategy and Policy Development ($0.120 million in 2023);
- Privacy Management Program ($0.100 million in 2023);
- Cyber Security Framework ($0.140 million in 2024);
- WRGS Thermal Assessment & Permitting ($0.413 million in 2024);
- Transmission Line Detailed Inspection Program ($0.250 million in 2024);
- Gates/TIVs Certification Assessment System Wide ($0.200 million in 2024);
- Digital Reporting Review ($0.125 million in 2024);
- Records Policy Planning and Program Development ($0.100 million in 2024); and
- Breaker Condition Assessment ($0.100 million in 2024).

Regulatory and Dam Safety Review: Rate base additions of approximately $1.486 million for the following projects:

- Dam Safety Review ($0.255 million in 2021);

- IPP Standing Offer Implementation ($0.326 million in 2021, $0.070 million in 2023);
- Atlin EPA Section 18 Proceeding (Hearing Reserve Account) ($0.386 million in 2023);
- Public Safety Plans ($0.225 million in 2023); and
- Vegetation Management Plan Update ($0.225 million in 2023)."

QUESTION:

a) Please explain why Whitehorse Post-Flood Assessment 2022 was not included in last GRA.

b) Explain how each of the projects listed under Feasibility Studies and Regulatory and Dam Safety Reviews enhance YEC's dependable capacity.

c) Please explain why each of the Feasibility Studies and Regulatory and Dam Safety Reviews were not completed by the ever-increasing levels of YEC personnel and management, including more engineers, as part of their jobs.

d) Since the IPP was a YTG initiated program, please explain why the IPP Standing Offer Implementation was not paid for by Yukon Development Corporation instead of ratepayers.

ANSWER:

(a)

This project was not completed or forecast to be completed in 2021, as such it was not included in the 2021 GRA.

(b)

The first quoted paragraph was in reference to "Major Deferred Projects > $1 Million". The quoted list of projects is from "Deferred Projects between $100,000 and $1 Million". It was never claimed that all projects listed under Feasibility Studies and Regulatory and Dam Safety Reviews enhance YEC's dependable capacity.

(c)

YEC strives to maintain an appropriate balance of in-house and outsourced capacity to delivery programs. The volume of work required to deliver the referenced deferred cost projects well exceeds the capacity of YEC personnel and is a small part of the larger program the personnel are required to deliver. Additionally, much of the work that falls under deferred cost projects requires capacity that does not exist, often due to specialized nature, and is not necessary within YEC. Therefore, building such capacity within YEC would not be prudent or sustainable. Where necessary YEC relies on external expertise to undertake work and provide recommendations for programs. YEC personnel oversee the tendering and delivery of the projects.

(d)

Please see the response to the same question for UCG-YEC-1-14(b).

REFERENCE: **Application, Tab 5-4 – Intangible Assets, page 5-12**
"Intangible assets impacting test year rate base additions are reviewed in Tables 5.2 to 5.6 and include costs related to development of an asset management framework (i.e., PAMMS Asset Management Framework and Enterprise Asset Management Purchase and Implementation), as well as smaller projects relating to EAM Enhancement review, CIS replacement, P&C Central Event Data Collection System and SharePoint Upgrades."

QUESTION:

a) Please explain how each of the intangible assets enhance YEC's dependable capacity.

b) Please explain why this money was not used to enhance YEC aging infrastructure to enhance dependable capacity rather than on projects "without physical substance".

c) Please explain how each of these intangible assets will result in monetary benefits to ratepayers (i.e., will they require less staff to run YEC, will they require fewer consultants to complete YEC work, etc.).

ANSWER:

(a), (b) and (c)

See Appendix 5.3A for a detailed business case justification of intangible asset projects over $1 million; and Appendix 5.3B for a detailed justification of intangible assets between $100,000 and $1 million).

The majority of intangible asset costs in the test years ($10.006 million) relate to the EAM and PAMMS projects. YEC is confronted with aging assets and the requirement for significant and ongoing investments in sustaining and growth capital. Improvements to asset management practices are required to ensure that YEC continues to meet industry standards and to ensure that investments are prioritized and managed in a manner that benefits ratepayers. The Board also accepted in Order 2022-03 (para 332 of Appendix A) "…that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000".

The detailed justification for the EAM and PAMMS projects is outlined in Appendix 5.3; Attachment 5.3A-1: Asset Management Business Case (Metsco) notes in summary (Page 5.3A-1 – 8):

> YEC relies on its physical assets, including generation and transmission assets, to achieve its business goals. However, the majority of its key assets were constructed in the 1950s and 1970s and require regular maintenance and refurbishment. As YEC is looking at significant investment in sustaining and growth capital, a comprehensive approach to asset management is crucial to ensure these investments provide the expected life of the assets for the benefit of the ratepayer without impacting services. Effective asset management requires a holistic approach, aligning asset management with strategic initiatives, and involves identifying, acquiring, maintaining, tracking, upgrading, and disposing of assets to maximize their value while minimizing risks. Failure to prioritize asset management can lead to decreased customer satisfaction, regulatory penalties, and rising costs associated with reactive maintenance. To ensure sustainable growth, YEC identified an opportunity to improve its asset management practices, leveraging Information Technology (IT) and Operational Technology (OT) and data analytics to develop a holistic and integrated strategy to align with the digitization of its operations.

Intangible projects between $100,000 and $1 million that are to be included in rate base by the end of 2024 total $0.766 million (the business case for each project is outlined in Appendix 5.3B). Overall, these projects are focused on required software and other upgrades, including required replacement of the current billing system; and projects are required to ensure that YEC can continue to operate effectively and meet its customers' needs.

REFERENCE: **Application, Tab 5-4 – Intangible Assets, page 5-13**
Major Projects > $1 Million – Rate Base Additions
"PAMMS Asset Management Framework – Rate base addition of $5.466 million in 2023 – approximate expenditures $0.439 million in 2018, $1.349 million in 2019, $1.530 million in 2020, $0.303 million in 2021, $0.835 million in 2022 and $1.011 million in 2023."

QUESTION:

a) Please explain how any of the costs for the PAMMS Asset Management Framework project were accounted for in the 2021-2022 GRA.

b) Please explain why the 2018, 2019, 2020, 2021 and 2022 costs associated with the PAMMS Asset Management Framework project were not recorded in rate base in the last GRA.

c) Please confirm that this reference identifies all of the costs associated with the PAMMS Asset Management Framework project. If not, please identify all other costs associated with this project.

ANSWER:

(a)

The PAMMS project was not complete in 2021 (the test year for the 2021 GRA) and were not forecast to be completed in 2021 (i.e., were not included in 2021 forecast costs). PAMMS costs remained in WIP at the end of the 2021 test year and therefore did not impact revenue requirement for the test year. There was no 2022 GRA.

(b)

As noted in the response to (a) the PAMMS project was not complete in 2021 – the Application states that it was not completed until 2023. As such, costs prior to 2023 related to the project remained in WIP and were not included in rate base or revenue requirement.

(c)

Confirmed.

REFERENCE: **Application, Tab 5-4 – Intangible Assets, page 5-13**
Major Projects > $1 Million – Rate Base Additions
"Enterprise Asset Management (EAM) System Purchase and Implementation – Rate 7 base addition of $4.550 million in 2021 – approximate expenditures $0.276 million in 2018, $0.534 million in 2019, $2.972 million in 2020 and $0.768 million in 2021."

QUESTION:

a) Please confirm whether the Enterprise Asset Management project is the predecessor of the PAMMS Asset Management Framework and explain how these two projects are connected.

b) Please explain whether any of the Enterprise Asset Management project is forecast to be placed in rate base in the 2023 or 2024 test years.

c) Please explain the rationale for spending $10.066 million on an intangible asset given the significant issues YEC has with dependable capacity.

d) Please provide details of if and when YEC Board approval was provided for this spending.

ANSWER:

(a)

EAM is not a predecessor of PAMMS. As reviewed in Appendix 5.3A of the Application, PAMMS was being developed when EAM was developed during the period 2018 to 2021.

Please see Appendix 5.3A which provides a detailed description and business case justification for the Physical Asset Management Managed System (PAMMS) Asset Management Framework; and the Enterprise Management System (EAM) Purchase and Implementation. Both the EAM and PAMMS are interrelated components of Yukon Energy's asset management program.

The PAMMS involves the formal documentation of all governance, roles and responsibilities, processes, and procedures required for the establishment and ongoing operation of YEC's asset management system. It is a multi-year project to update asset

management standards and practices to industry standards. The EAM relates to the purchase of an enterprise-level software application to enable YEC to manage and optimize its assets throughout the entire asset lifecycle, and implement the framework developed as part of the PAMMS process. The purchase of the EAM preceded completion of the PAMMS process.

(b)

Yukon Energy is seeking to include costs for the Enterprise Asset Management Project in rate base as part of the 2023/24 GRA. The project was completed in 2021 and brought into service at that time. For the purpose of rate setting, it is proposed to be included in rate base in the 2023/24 test years.

(c)

The $10.006 million amount relates to the cost of both the EAM and the PAMMS project. The justification for the EAM and PAMMS project is provided in Appendix 5.3A of the Application.

Given the volume, complexity and varying risk profiles of the assets used by YEC to execute its mandate, a computerized system is necessary for successful implementation of a modern, robust asset management strategy consistent with current industry standards. The existing system available in 2017 was assessed and determined to be incapable of hosting the required asset management program.

Utilities must develop asset management in accordance with modern requirements. This is a necessary requirement for prudent and efficient asset management, and not something to be traded off against other necessary capital project requirements. Please see response to UCG-YEC-1-33 (a-c).

(d)

See Appendix 5.3A of the Application – which notes that Yukon Energy's Board approved proceeding with both the EAM and the PAMMS (page 5.3A-3); and the YEC Board of Directors approved implementation of the Infor EAM solution in December 2019 (see page 5.3A-16).

REFERENCE: **Application, Tab 5-4 – Intangible Assets, page 5-13**

Intangible Projects between $100,000 and $1 Million – Rate Base Additions

"Rate base additions from 2021 to 2024 in each intangible assets cost activity totaling between $100,000 and $1 million that impact 2024 rate base are summarized below (total rate base impact in 2024 test year of approximately $0.766 million, excluding reductions due to amortization, reflecting $0.147 million additions in 2022, $0.368 million additions in 2023, and $0.250 million additions in 2024). These rate base additions relate to the following projects:

- EAM Enhancements Review ($0.147 million in 2022);
- Network Software Traffic Shaping ($0.250 million in 2023);
- CIS Replacement ($0.118 million in 2023);
- P&C Central Event Data Collection System ($0.150 million in 2024); and
- SharePoint Upgrades ($0.100 million in 2024)."

QUESTION:

a) Please explain the purpose and justification for each of these projects.

b) Please provide details on if and when YEC Board approval was provided for each of these projects.

c) Please explain how each of these projects enhance YEC dependable capacity.

d) Please confirm that "CIS" refers to the Customer Information System and that "P&C" refers to Protection and Control.

ANSWER:

(a)

The purpose and justification for these projects is provided in Appendix 5.3B.

(b)

For 2022 and 2023 projects, YEC Board approval was provided as part of the annual capital plan approval process (typically in December of the prior year). 2024 projects were reviewed by the YEC Board prior to approval to submit the Application, but have not yet been specifically approved by the YEC Board as the capital budget approval process typically occurs annually in December of each year.

(c)

The primary driver of these projects is not the enhancement of dependable capacity.

(d)

Confirmed.

TOPIC: **Diesel Rental Business Case**

REFERENCE: Reference: Application, Appendix 3.1 – Diesel Rental Business Case

"Appendix A of Board Order 2022-03, paragraph 115, provided the following direction for YEC to provide a diesel rental business case in its next GRA:

> "The Board directs YEC to provide a specific business case going forward for the diesel units (rental, lease and own/resale), other alternatives to rentals and stronger emphasis to least-cost options, the rationale for the options and the timing to implement such options. Of particular interest to assist in evaluating comparisons of Levelized Costs of Capacity would be a sensitivity analysis that includes delays in planned permanent renewable capacity projects and higher-than forecast peak demand growth over the next 10 years. The Board directs YEC to provide a business case that conforms with these business case criteria in its next GRA".

In accordance with this direction, YEC has considered the following possible alternatives to the proposed short-term rental of twenty 1.8 MW diesel rental units (excluding spares) for the purpose of meeting the N-1 dependable capacity criteria requirement during winter 2023/24 and winter 2024/25:

- Purchase of diesel rental units, and subsequent resale of those units when they are no longer needed (i.e., the "own/resale" option described above);
- Longer term "lease" of diesel rental units, instead of the short-term rental of diesel units proposed by YEC (i.e., rentals for less than five months during a winter season); and
- Reliance on the addition of new capital facilities that are forecast to be commissioned during the GRA test years, including both the Battery Energy Storage System (BESS) project and the 6.5 MW of new permanent diesel capacity at Dawson that are forecast to be commissioned in 2024." [Application p.3.1-1]

QUESTION:

a) Please provide details of any other supply-side and demand-side options considered by YEC to at least reduce the proposed need to rent 20 diesel-fuelled generation units.

b) Please identify where YEC reviews the sensitivity of higher-than forecast peak demand growth over the next 10 years.

c) Please provide an update on the status of the review and update of the 10-Year Renewable Electricity Plan to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro project.

ANSWER:

(a)

In 2023, Yukon Energy launched Peak Smart Home (I.e., residential demand response program), a demand-side management (DSM) program that aims to reduce peak demands for power by shifting the time power used by program participants to off-peak hours. Additional DSM programs are also being contemplated. More information about those programs can be found in GRA Application, Section 5.2A-2 on DSM Program Development and DSM Program 2022-2030.

These programs, however, do not address the short-term need for diesel rentals as currently planned for the purpose of meeting the N-1 dependable capacity criteria requirements for winter 2023/24 and winter 2024/25. The portfolio will be implemented in a phased approach. The first program, Peak Smart Home was launched in November 2023. The portfolio's target is to provide at least 7 MW of dependable capacity by 2030 [DSM is expected to reduce the N-1 peak by about 0.6 MW by 2024].

The details are provided in Appendix 5.2A, section 5.2A-2.

Please also see the response to YUB-YEC-1-82.

(b) and (c)

Yukon Energy is developing an Electricity Supply Plan to update short-term forecast electricity generation needs for the next 5-10 years and develop an updated workplan for meeting forecast electricity demand during winter peak and N-1 events during this period. The Electricity Supply Plan is expected to be released by mid-2024. It will consider the status of projects proposed in the 10-Year Renewable Electricity Plan, update the near-term forecast capacity and energy gap, and update the plan to meet Yukon's electricity needs in the near-term.

Yukon Energy is also developing an updated long-term resource plan under the 2024 Resource Plan to be completed in late 2025. The updated Resource Plan will cover sensitivity for low and high load cases.

REFERENCE: Reference: Application, Appendix 4.2 – Bill Impacts Comparison

QUESTION:

a) Please explain the relevance to the YUB and Yukoners of comparing the bills paid to YEC to the bills paid to electricity users throughout Canada.

b) Please provide details on the most significant cost drivers for the bills paid in the NWT Thermal Zone, Iqaluit and Yellowknife.

c) Please explain how the bills paid in the NWT Thermal Zone, Iqaluit and Yellowknife are comparable to the bills paid in the Yukon.

ANSWER:

(a)

Each jurisdiction has its own context and circumstances affecting rates and customer bills, however, the bill comparisons provide the Board and ratepayers with an ability to see how Yukon electricity bills compare to electricity bills in other jurisdictions.

(b)

At a high level, key cost drivers in the NWT Thermal zone include increased thermal-based power production costs (fuel and natural gas), and increased capital costs associated with new capital investments.[1]

Distribution service in Yellowknife is provided by NUL(Yk) who purchases power from NTPC. Purchased power is the bulk of NUL's revenue requirement. The primary cost driver for NTPC's Snare zone (which includes Yellowknife) is non-fuel operations and maintenance expense related to NTPC's strategic priorities.[2]

[1] See NTPC 2022-23 General Rate Application, page 3-6.
[2] See NTPC 2022-23 General Rate Application, page 3-5.

For Iqaluit, 2022/23 GRA key cost drivers included O&M, capital and fuel costs.[3] However, subsequent to the 2022/23 GRA, the most significant cost driver relates to cost of fuel changes[4].

(c)

Each of these are northern jurisdictions – however, bills paid are affected by the context affecting rates in each jurisdiction. Yukon is a predominantly hydro-based jurisdiction with legacy hydro assets in place and equalized rates for hydro and thermal generation regions that help to ensure overall lower cost power bills compared to other thermal-based areas of the north.

[3] Executive Summary Qulliq Energy Corporation 2022/23 General Rate Application, page 3.

[4] See the following for further details: Qulliq Energy Corporation 2022/23 Base Energy Rate Amendment Application, page 1-3.

Yukon Utilities Board
(YUB)

REFERENCE: **YEC 2023-24 General Rate Application (Application), PDF page 4**

ISSUE: Rental and operation of diesel generators

QUOTE: The Yukon's peak demand for electricity has increased by 23% in the last five years [from 2017 to 2022] and this trend is expected to continue with an additional 36% increase in non-industrial peak by 2030. Meeting these peaks demands for power in the short term requires the rental and operation of diesel generators each winter until new sources of dependable capacity can be built or connected to the Yukon grid.

QUESTION:

a) When did YEC begin using rented diesel generators?

b) When does YEC expect to cease using rented diesel generators?

c) Please provide a table showing the following:

   i. The number of diesel generators rented, the total rented generator capacity, available generation capacity before rented diesel generators, YEC firm load capacity requirements (actual and then forecast capacity to the year that diesel generators are no longer required) for each year from the start of the use of rented diesel generators to the time that rented diesels generators are no longer required. Please identify by year the number of units considered as spares; and

   ii. Add four further columns to the table showing, by year, each of the following for the rented diesel generators: (1) the rental costs; (2) the maintenance costs; (3) the delivery and removal costs; and (4) the connection and disconnection costs.

d) YEC has previously stated that part of the rental agreement for the diesel generators requires operation on those generators for certain minimum periods. Please provide a table showing the annual generation costs of the rented diesel generators (variable costs such as fuel), the kWhs of electricity generated by each rented diesel generator, the kWhs of non-rented diesel generation displaced by

running the rented diesel generators ahead of lower cost generation sources and the variable costs such as fuel of the non-rented diesel generation sources. Please provide this information for each year since the start of the use of rented diesel generators to the year that YEC expects to cease renting diesel generators.

e) Please provide copies of the rental agreements by year for each year YEC has rented diesel generators.

ANSWER:

(a) – (c)

YEC started renting diesel units for the 2017/18 winter season with 4 diesel units. YEC expects the diesel rentals will continue until permanent renewable and/or thermal capacity is developed and in place to displace diesel rentals.

YEC is developing an Electricity Supply Plan to identify the resource options that can be implemented in the next 5-10 years to increase the supply of dependable capacity and energy during the winter months and reduce the use of rental diesels. The Electricity Supply Plan is expected to be released by mid-2024. It will consider the status of projects proposed in the 10-Year Renewable Electricity Plan and outline a workplan to meet Yukon's electricity needs in the next 10 years. Yukon Energy is also working on a Resource Plan in 2024 and 2025. The Resource Plan is a long-term plan (beyond 10 years) that will determine Yukon's long-term electricity needs and identify resource options that are best suited to meet those needs.

YUB-YEC-1-1 Attachment 1 shows the requested information for the 2017/18 – 2028/29 winter seasons. The forecast years are based on information available today and will be updated when the Electricity Supply Plan and Resource Plan are each developed. Pending completion of the Electricity Supply Plan and the Resource Plan, YEC is not able to provide useful forecasts on this matter beyond winter 2028/29.

The forecast diesel rentals starting in winter 2023/24 in YUB-YEC-1-1 Attachment 1 are based on forecast N-1 dependable capacity (and related N-1 dependable capacity shortfall) as determined in Table 1 below, including planned/ committed dependable capacity supply options as described in Table 1.

Table 1 shows the number of diesel rental units before and after planned/committed supply options.

Table 1: Forecast Number of Diesel Rentals – Winter 2023/24 -2028/29

	Before Committed and Planned Supply Options		With Diesel Replacements, Dawson Diesel Expansion, BESS and DSM							With Diesel Replacements, Dawson Diesel Expansion, BESS, DSM and Atlin		
	N-1 Capacity (Shortfall), MW	Number of Diesel Rentals excluding spares	DSM, MW	Diesel Replacements, MW	Added Diesel in Dawson, MW	BESS, MW	Total Added Dependable Capacity, MW	N-1 Capacity Shortfall, MW	Number of Diesel Rentals excluding spares	Added Dependable Capacity, MW	N-1 Capacity Shortfall, MW	Number of Diesel Rentals excluding spares
	A	B=A/1.8	C1	C2	C3	C4	C=C1+C2+C3 +C4	D=A-C	E=D/1.8	F	G=D-F	H=G/1.8
2023/24	35.4	20	0.1				0.1	35.3	20	0.0	35.3	20
2024/25	41.6	24	0.6	5.0			5.6	36.0	20	0.0	36.0	20
2025/26	44.2	25	1.0	13.25	3.25	7.0	24.5	19.7	11	0.0	19.7	11
2026/27	47.7	27	2.0	13.25	3.25	7.0	25.5	22.2	13	8.8	13.5	8
2027/28	51.7	29	4.0	13.25	3.25	7.0	27.5	24.2	14	8.8	15.4	9
2028/29	56.3	32	6.0	13.25	3.25	7.0	29.5	26.8	15	8.8	18.0	10

Notes:

1. Column A assumes N-1 Peak Demand (MW) as provided in YUB-YEC-1-1 Attachment 1 and N-1 dependable capacity before planned/committed dependable capacity supply options described in Table 2.
2. Column C2 includes 5 MW Faro diesel replacement available for 2024/25, 5 MW Whitehorse diesel replacement available for 2025/26, 3.25 MW Dawson [Callison] diesel replacement available for 2025/26. Column C3 includes 3.25 MW additional diesel in Dawson [Callison] available for 2025/26.
3. Column F assumes Atlin EPA in-service in time to provide 8.75 MW of dependable capacity for winter 2026/27.

Table 2 summarizes the rental costs by location for the 2023/24 and 2024/25 winter seasons. The rental contracts are signed separately for each location as provided in response to (e) below.

Table 2: Rental Units Winter 2023/24 & 2024/25 and 2023-2024 Calendar Year Cost by Location

	2023/24		2024/25			
	Total number of units	Spares	Total number of units	Spares	2023 Calendar Year Cost	2024 Calendar Year Cost
					$ millions	$ millions
Whitehorse	10	1	10	1	2.6	2.9
Faro	7		7		2.5	2.8
Mayo	5	1	5	1	0.3	1.7
Total	**22**	**2**	**22**	**2**	**5.5**	**7.4**
Spares					0.5	0.6
Total net of spares					**5.0**	**6.8**

Note:
2023 includes cost from 2022/23 for Jan-Apr and from 2023/24 for Dec
2024 includes cost from 2023/24 for Jan-Apr and from 2024/25 for Dec

In 2021/22 and 2022/23 winter seasons some of the units remained in Whitehorse and Faro and YEC paid "stand down fees" for six months May through October [i.e., the units remained in Yukon, but not used]. After the 2022/23 winter season ended YEC kept eight units in Whitehorse and four units in Faro for the 2023/24 winter season. Three units out of eight units held in Whitehorse for the 2023/24 season and two units out of four units held in Faro were sent to Mayo by YEC.

(d)

The diesel units are rented for N-1 dependable capacity purposes, therefore, there is no projection for the energy required from rental diesels for maintenance purposes or to meet the load demand.

However, the diesel rentals are also used to support peak load demand when there is a need for diesel generation because as part of the rental contract, YEC pays for 500 hours of use per engine per season regardless if they are used or not. YEC uses this allowance and runs diesel rental units during the winter season as they are smaller than available YEC owned units and have lower emissions of pollutants than YEC's Pre-Tier 4 permanent diesel units. YEC's air emissions permits require the operation of units in the order of highest efficiency from an air pollution perspective. It is also more economical to use rental units as the hours of their use has already been paid for. This also reduces running hours and maintenance costs for YEC owned diesel units. The actual generation

from the rental units will depend on demand and available supply from hydro units, IPPs and LNG and will vary year over year. Therefore, no forecast is available.

The following table shows the actual generation from diesel rental units by year [the full information for 2017/18 is not available]. YEC does not separately record diesel fuel litres used by rental units, therefore, the litres are estimated based on total diesel fuel usage.

As indicated above, the forecast diesel rental energy will depend on the actual load on the grid and available hydro, IPP and LNG generation, and therefore no forecast is available for winter seasons beyond 2022/23.

Table 1: Diesel Rental Unit Actual Generation & Estimated Diesel Fuel Use by Winter Season (2018/19-2022/23)

Winter Season	GWh	Estimated Litres, million litres
2018/19	0.8	0.2
2019/20	7.5	2.1
2020/21	9.1	2.5
2021/22	11.1	3.2
2022/23	8.9	2.1

(e)

Yukon Energy cannot provide the rental agreements as requested as the agreements contain confidential information which if made public could significantly harm or prejudice YEC's competitive negotiating position [as noted in response to YUB-YEC-1-24 (f), YEC is working through a tender process for rental options] and the existing supplier has requested these contracts be kept confidential as it could impact the tender process. Should the Board consider it necessary to review these agreements – Yukon Energy would be willing to provide copies to the Board for review on a confidential basis in accordance with the Board's rules of practice.

Winter Season	N-1 Dependable Capacity before rentals, MW	N-1 Peak Demand [forecast], MW	N-1 Capacity Shortfall before rentals, MW	Total Number of diesel rentals	Including		Capacity of total diesel rentals, MW	Spares, MW	Equipment rental cost, $000	Transportation cost, $000	Maintenance/ usage cost, $000	Start-up/ Commissioning/ Engineering cost, $000	Stand-down cost, $000	Total rental cost, $000
					To close N-1 Capacity Shortfall	Spare Units								
2017/18	76.7	84.6	-7.9	4	4		7.2		$644.4	$63.0	$10.6	$0.1	$0.0	$718.1
2018/19	76.7	87.0	-10.3	6	6		10.8		$1,241.0	$201.1	$94.5	$0.0	$0.0	$1,536.7
2019/20	73.6	89.6	-16.0	9	9		16.2		$1,555.5	$252.9	$11.3	$74.1	$0.0	$1,893.8
2020/21	73.6	99.3	-25.7	17	15	2	30.6	3.6	$3,006.3	$436.3	$45.0	$98.3	$566.1	$4,151.9
2021/22	75.8	102.8	-27.0	17	15	2	30.6	3.6	$2,917.5	$94.5	$42.8	$92.8	$809.6	$3,957.1
2022/23	76.8	103.0	-26.2	17	15	2	30.6	3.6	$2,899.8	$144.2	$59.9	$59.3	$674.1	$3,837.3
2023/24F	74.4	109.6	-35.3	22	20	2	39.6	3.6	$5,284.6	$1,523.1	$154.2	$136.5		$7,098.4
2024/25F	77.3	113.3	-36.1	22	20	2	39.6	3.6	$5,208.7	$2,148.4	$160.4	$149.5		$7,667.0
2025/26F	96.3	116.0	-19.7	13	11	2	23.4	3.6	$3,347.8	$1,278.4	$98.6	$89.6		$4,814.3
2026/27F	106.0	119.5	-13.5	9	8	1	16.2	1.8	$2,598.1	$883.6	$71.0	$62.3		$3,614.9
2027/28F	108.0	123.4	-15.4	10	9	1	18	1.8	$2,977.9	$1,063.0	$82.0	$75.8		$4,198.7
2028/29F	110.0	128.0	-18.0	12	10	2	21.6	3.6	$3,503.7	$1,288.2	$102.3	$89.3		$4,983.5

Note: The rental cost breakdown between components for the actual years is impacted by the coding at the time of invoicing and may not accurately reflect the cost for a specific component. It is also impacted by accruals and/or other adjustments for previous years/months. These also impact the cost breakdown for the winter seasons.

REFERENCE: **Application, PDF page 5**

ISSUE: Revenue shortfall

QUESTION:

a) Please explain what is meant by YEC's statement that as a factor driving the 2023-24 revenue shortfall, rate increases are needed "To recover the costs of doing business in a better way."

b) Please provide concrete examples of the costs proposed to be incurred that will result in YEC "doing business in a better way."

ANSWER:

(a) and (b)

The reference to "doing business in a better way" includes, for example, Yukon Energy's concerted efforts to develop and strengthen long-term mutually beneficial relationships with First Nation and municipal governments in the areas we serve. It means early engagement and ongoing collaboration with Yukon First Nations in each of the project areas where we are looking to renew our license or permits to understand interests and values of the Nations, how our projects and operations affect those values, and the types of mitigations needed to address the effect. Doing business better also means establishing and delivering on long-term processes and commitments to continually monitor, adapt and mitigate effects of the ongoing operations of our facilities and to fulfill the terms and conditions of our regulatory permits and authorizations, and agreements with each of the Nations.

These efforts and objectives are particularly critical given the fact that all three of YEC's hydroelectric generation stations are in the renewal stage. Those renewals are subject to in-depth assessment by the Yukon Environmental and Socio-economic Assessment Board ("YESAB"), as well as public hearing processes before the Yukon Water Board, and they all require extensive engagement and collaboration with Yukon First Nations, in the project areas the Yukon Government, and the Department of Fisheries and Oceans.

YEC's air emission permits in Whitehorse and Dawson City also need to be renewed and are also subject to assessment by YESAB.

In today's social, political and regulatory environment, the complexity and workload needed to participate and manage these multi-party processes is significantly greater than it was historically.

In this context, concrete examples of costs proposed to be incurred that will result in YEC "doing business in a better way" include:

- The addition of a permanent 1.00 FTE for a Manager of Community Relations;
- The addition of a permanent 1.00 FTE for an Environmental Compliance Project Manager / Coordinator; and
- Increased environmental monitoring activities required by regulatory authorities in connection with the renewal of the water license for the Aishihik Generating Station.

Doing business in a better way also includes YEC's approach to obtain, to the greatest extent possible, the support of First Nation governments and the public of proposed projects before incurring significant project costs. For example, early in the research phase for the Moon Lake Pumped Storage project, YEC learned that at this time, there was not full First Nations support of the proposed project which is located in an area of transboundary land claim discussions with multiple layers of governments involved. YEC stopped significant spending on this project to allow more time for additional conversations with First Nation governments to occur.

More generally, a change in YEC's approach to its 2024 Resource Plan will see YEC working together with Yukon First Nations to the greatest extent possible during the planning process to identify potential resource options in different regions of the Yukon that could meet the Yukon's future electricity needs before YEC spends significant costs on a specific project for which social license may not exist or be obtained. A desired outcome of the future Resource Plan is that potential First Nation proponents would come forward to YEC with potential project ideas that meet the electricity needs of the Yukon instead of YEC making unilateral decisions about projects it plans to advance. YEC would also seek First Nation support to proceed through the early development phases of any proposed project so that interests and issues can be explored and resolved in a manner that provides greater confidence in the financial and human resources that are needed to move projects forward.

REFERENCE: **Application, PDF page 5**

ISSUE: Isolated grid

QUOTE: As the primary generator and transmitter of electricity in Yukon, it is YEC's responsibility to lead these changes. On an isolated grid, these investments are even more paramount. YEC cannot import electricity when needed or export power to other jurisdictions when there is a surplus. For YEC and Yukoners, this means we only have ourselves to rely on to ensure there is enough capacity to reliably generate the electricity Yukoners need now and in the future.

PREAMBLE: Recently, YEC completed a Board proceeding regarding the YEC Tlingit Homeland Energy EPA. The total capital cost for that project providing approximately 8.75 MW of firm capacity is greater than $250 million.

QUESTION:

a) What analysis has YEC done regarding connecting the Yukon Integrated System (YIS) to another grid such as the BC grid?

b) Considering the price of more than $250 million for 8.75 MW of capacity, what is the crossover cost point for connecting to another grid versus constructing or contracting for new capacity? Please provide supporting details for the manner in which this crossover point was determined.

ANSWER:

(a)

Due to interprovincial/territorial complexities, the work today on potential connection of the YIS to the BC grid is being led by Government of Yukon with the Government of British Columbia. The only analysis done by Yukon Energy on this potential interconnection is the 2019 report that Yukon Energy received from Midgard Consulting Inc titled "Yukon – British Columbia Interconnection Development Plan".

(b)

The Atlin Hydro Expansion Project is an IPP project proposed for construction by Tlingit Homeland Energy LP (THELP), a development corporation of the Taku River Tlingit First Nation (TRTFN). The project would be built, paid for and owned by THELP. As referenced in the YEC/THELP EPA for the proposed project, YEC would only pay THELP for dependable capacity and energy delivered to the Yukon grid from the project each year. For clarity, the capital cost referenced by the YUB of more than $250 million would be incurred by THELP as the project proponent and not by YEC.

Atlin is not connected to the BC electricity grid. The referenced capital cost is mainly for expansion of the existing TRTFN-owned hydro project currently supplying the remote/ isolated Atlin community, and a transmission line to connect the expanded hydro facility in Atlin to the Yukon grid. This project accordingly does not provide any basis for assessing acceptable cost cross over points for connecting the Yukon grid to the BC electrical grid – the Atlin EPA project comparators are other renewable capacity options for Yukon that can be developed in comparable time periods.

The response to “a” above indicates studies to date regarding connecting the YIS to the closest external electricity grid, i.e., to the BC grid.

When contemplating any new interconnection, consideration is required of a range of factors rather than attempting to estimate a single “cross over cost point”. Yukon experience in assessing and developing internal grid connections (e.g., connecting the WAF and MD grids) highlights the need to consider a number of factors related to the potential connection including, but not limited to:

- Potential benefits of the connection to support more effective use of existing and potential newly developed renewable generation resources, e.g., connection of WAF and MD grids enabled the Mayo B hydro expansion project to be developed;

- The scope and costs required to develop new connections;

- The scope and cost of upgrades needed to the existing electricity system to support the connection and to ensure reliable grid operations after the connection is made;

- Federal and other grant funding supports provided for any new connections; and

- The need to ensure applicable back-up dependable capacity is retained to address any failures in the grid connections.

REFERENCE: **Application, PDF page 7; PDF page 141, Tab 5 tables, Table 5.2, Work in Progress Continuity Schedule – 2021; PDF page 156; PDF pages 184-192, Section 5.1A-14: WH2 Uprate Construction and Engineering (rate base addition of $7.078 million to 2021 GRA approved); and PDF pages 193-197, Section 5.1A-15: WH4 Servomotor Replacement (rate base addition of $0.789 million to 2021 GRA approved)**

ISSUE: Disallowed portion of two capital projects added to rate base resulting in 2023 and 2024 rate increases

QUOTE: PDF page 7:

- Capital Cost rate base additions - $7.9 million for WH 2 Uprate and WH4 Servomotor Replacement (the portion previously disallowed by the YUB).

PDF page 156:

- Capital investments on New Supply options to maximize renewable energy generation – Net rate base impact of approximately $7.867 million addition to 2021 approved rate base:
  - WH2 Uprate Construction and Engineering – Actual cost for construction and engineering in 2021 of $12.358 million; and actual construction cost of $0.457 million in 2022. Total in service cost of $12.814 million, of which $5.736 million was approved cost added to rate base following the 2021 GRA3 – addition of $7.078 million to 2021 rate base is now sought.
  - WH4 Servomotor Replacement – Actual cost of $1.318 million in 2021 and $0.019 million in 2022. Total in service cost of $1.337 million at the end of 2022, of which $0.548 million was approved cost added to rate base following the 2021 GRA4 – addition of $0.789 million to 2021 rate base is now sought.

3 Board Order 2022-03, Appendix A, para 278.
4 Board Order 2022-03, Appendix A, para 282.

PDF page 184:
Board Order 2022-10 regarding YEC's 2021 GRA disallowed over 50% of YEC's capital costs for the Whitehorse Hydro #2 (WH2) Uprate project, noting (Appendix A, para 277-278) that YEC never discussed the reasons for cost differences between the earlier Hatch study estimates and YEC's actual costs, nor did it adequately explain the reasons the project was the preferred alternative. Board Order 2022-10 (Appendix A, para 38) rejected YEC's application for review and variance of this decision on the WH2 Uprate costs, noting that the Board relied on the evidence and arguments before it in making the findings to reduce the costs, and that generally the Board found that the business case was deficient for this project and that there was a lack of information in the other evidence to justify the significant cost increases and a lack of an adequate justification of costs and benefits.

PDF page 193:
Board Order 2022-10 regarding YEC's 2021 GRA disallowed over 60% of YEC's capital costs for the Whitehorse Hydro #4 (WH4) Servomotor Replacement project, noting (Appendix A, para 281-282) that YEC did not provide an adequate business case or justification that supports the significant cost increase from the original Hatch cost estimate, and that the benefits espoused by YEC do not fully justify the costs that were incurred or forecast for this project.

Board Order 2022-10 (Appendix A, para 38) rejected YEC's application for review and variance of this decision on the WH4 Servomotor Replacement costs, noting that the Board relied on the evidence and arguments before it in making the findings to reduce the costs, and that generally the Board found that the business case was deficient for this project and that there was a lack of information in the other evidence to justify the significant cost increases and a lack of an adequate justification of costs and benefits.

PREAMBLE: In Board Order 2022-03, Appendix A, pars. 278 and 282, the Board denied certain of YEC's capital costs for the two referenced projects. YEC's review and variance application was also denied at the phase 1 stage in Board Order 2022-10. The Board seeks to understand how the circumstances of the previous disallowances can be altered by the information now being provided by YEC in the current Application.

QUESTION:

a) Please explain on what regulatory and/or legal basis YEC is asking the Board to examine the disallowed costs for the WH2 and WH4 assets which YEC has now added to its rate base.

b) Please provide the date on which the WH2 and WH4 projects resulted in used and useful utility assets.

c) Please provide the date on which the WH2 and WH4 projects were recorded as capital assets in YEC's accounting records.

d) Please confirm that, notwithstanding Application, PDF page 141, Tab 5 tables, Table 5.2 – Work in Progress Continuity Schedule – 2021 shows capital additions in the year 2021 appearing to include the disallowed portions of WH2 Uprate and WH4 Servomotor projects, YEC's 2023-24 revenue requirement has not sought any recovery of revenue associated with the disallowed portion of the project costs for the years 2021 or 2022.

e) Should the requests for costs for these projects from 2021 be considered as retroactive ratemaking? Please explain why or why not.

ANSWER:

(a)

The Board retains authority and responsibility under the *Public Utilities Act* (the "Act") in each GRA Application to review utility capital costs incurred to date, or forecast to occur during the current test years, for assets that are forecast to be used and useful during the current GRA test years. The Board's authority and responsibility to carry out this review is to determine if these costs are prudent and reasonably incurred and therefore to be included in the forecast revenue requirement for the current test years.

In particular, it is the Board's obligation under section 32(1) and (3) of the Act in each GRA Application to determine a rate base for the property of the utility that is used or required to be used to provide service to the public, giving 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.

The mere fact the Board may have concluded in a previous GRA Application that there was insufficient evidence in that proceeding to support including the costs of certain assets in YEC's rate base for a previous test year does not displace the Board's statutory obligation to include costs in YEC's rate base for the current test years that are supported by sufficient evidence in the current proceeding.

In the specific instance of disallowed capital costs in Board Orders 2022-03 and 2022-10 for the WH2 and WH4 assets, the Board did not disagree with YEC's assertion that the assets were used and useful. The sole basis provided by the Board for disallowing some of the incurred or forecast costs was that the Board relied on the evidence and arguments then before it, and that generally the Board found that the business case then before it for each of these projects was deficient and that there was a lack of information in the other evidence then before it to justify the significant cost increases and a lack of an adequate justification of costs and benefits.

The WH2 and WH4 assets continue to be used and useful in the 2023 and 2024 test years for the current Application, and YEC has provided additional information and clarifications on the relevant costs for these assets in order to address the information deficiency issues raised by the Board in its earlier Orders related to the prior 2021 YEC GRA.

(b)

The WH2 project was considered used and useful on November 23, 2021. The WH4 project was considered used and useful on May 26, 2021.

(c)

The WH2 project was recorded as a capital asset on November 23, 2021. The WH4 project was recorded as a capital asset on May 26, 2021.

(d)

Not confirmed. As disclosed on Page 5-5 and 5-6 of the Application, YEC is seeking recovery of rate base additions of $7.078 million to 2021 approved rate base relating to

the WH2 Uprate Construction and Engineering total in service cost of $12.814 million, of which $12.358 million was spent in 2021 and $0.457 million in 2022. As disclosed on Page 5-6, YEC is seeking recovery of rate base additions of $0.789 million to 2021 approved rate base relating to the WH4 Servomotor Replacement total in service cost of $1.337 million, of which $1.318 million was spent in 2021 and $0.019 million in 2022.

(e)

No.

In the current 2023-24 GRA Application, YEC is not requesting recovery of depreciation or return for the period from in-service (2021) to December 31, 2022. The current Application only seeks recovery on a prospective basis (i.e. commencing January 1, 2023, at the start of the test years applicable to this Application), based on the evidence and business cases provided to the Board in the current proceeding. This is consistent with the Board's statutory obligations under section 32 of the Act, and it cannot be considered to constitute retroactive rate making when YEC is not requesting any retroactive change to its revenue requirements or rates for 2021 or 2022 or for any other earlier time period that would constitute a request for retroactive ratemaking that is not provided for under the Act.

REFERENCE: **Application, PDF page 23**

ISSUE: Non-fuel Operating and Maintenance Expenses (O&M) - FTEs, vacancy rate and salary escalators

QUOTE:

Rising labour costs

For 2023, labour rates have been escalated by 4 percent, which is consistent with approved increases for Yukon government employees. For 2024, labour rates have been escalated by 3 percent also consistent with approved increases for Yukon government employees.

A vacancy factor of 9 FTEs has been applied to labour expenses for the 2023-2024 test years. This is based on a 5-year historical average. The vacancy factor for the 2021 GRA was 5 FTEs excluding 3 new FTEs the YUB directed to remove from the revenue requirements in its Order 2022-03, Appendix A.

Staff positions

YEC is forecasting an increase of approximately 19 FTEs in 2024 over the approved 2021 FTEs. However, YEC also increased the vacancy factor which reduces the impact on the net labour cost. The details of the 13 FTE additions are provided in Tab 3.

The additional positions, as outlined in Tab 3, are required to plan, permit, execute and deliver YEC's $85 million/year capital budget forecasted in the 2023 and 2024 test years and anticipated future capital requirements as the energy transition continues to unfold. YEC's forecast 2023 and 2024 annual capital programs are nearly double the size they were prior to 2021. Additional staff positions are needed who possess the training and knowledge to build and connect new projects to meet growing demands for electricity; to replace and upgrade assets that are nearing or at end-of-life; and to plan, deliver and oversee more complex projects with multiple groups of rightsholders and stakeholders, both in terms of scope and expenditures.

PREAMBLE: The Board requires further information.

QUESTION:

a) Please confirm that the referenced labour rate increases approved for "Yukon government employees" have historically been applicable to YEC employees and are inclusive of any collective bargaining agreement process currently in place for YEC employees.

b) Please clarify whether any portion of the forecast labour rate increase is applicable to inflation on base pay as opposed to increases applicable to YEC employee benefits.

c) If part (a) is not confirmed, please explain how YEC has forecast labour rate increases in the past. Please include an explanation of whether labour rates are proposed to differentiate between in-scope and out-of-scope employees and whether any collective bargaining agreements remain unresolved for the years 2023 or 2024 for YEC.

d) Please explain how the need for 19 additional full-time-equivalent (FTE) positions between 2021 approved 100.60 FTEs and 2024 forecast 119.81 FTEs reconciles with the forecast increase in vacancy rate between what was approved for 2021 (five FTE vacancy rate) and what is forecast for 2024 (9 FTE vacancy rate).

e) Given that the quote above seems to state that the need for 19 additional FTEs is largely related to YEC's forecast capital projects and related expenditures, please explain how these employees would be redeployed should YEC's capital forecasts not be approved by the Board or should the planned project execution of these capital forecasts not be achieved under YEC's proposed timelines.

f) Please provide the YEC calculation, which was based on a five-year historical average, determining a vacancy rate of nine FTEs for the 2023-24 test period.

ANSWER:

(a)

While YEC employees are not considered Yukon government employees, the Yukon government collective agreement heavily influences the results in negotiations between

YEC and its union as the Yukon government is considered the greatest market comparator. In all recent YEC collective agreements, arbitration/mediation resulted in YEC wage rate adjustments exactly equal to Yukon government wage rate adjustments.

Please note that while page 1-8 of the Application referred to a 2023 escalation of 4%, it should have stated 4.5%. All calculations in the Application were based on the Yukon government rate of 4.5%.

(b)

The labour rate increases of 4.5% for 2023 and 3% for 2024 are referring to base pay only. Changes in benefits are not part of those rates.

(c)

The approach to labour rate increases in this Application is consistent with the approach to labour rate increases in prior Applications where a collective agreement was not in place at time of filing.

Labour rate changes are proposed to be the same for in-scope and out-of-scope employees. This is also consistent with prior Applications and prior actuals.

The 2023-2025 YEC collective agreement was ratified by the Union in early November 2023 and approved by the YEC Board on November 8, 2023. Negotiated wage rate increases were 4.5% for 2023 and 3% for 2024, exactly equal to wage rate increases approved by the Yukon government.

(d)

There is no direct formulaic reconciliation between FTE additions and increases in vacancy rate, but there is the general reasonableness test that as the FTE count increases, so will the vacancy rate.

The vacancy rate of 9 in this Application is based on a formula consistent with vacancy rates formulas of prior Applications. The vacancy rate is equal to the average of the actual vacancy rates in the previous five years (see response to “f” below).

(e)

There may be exceptions, however, in general, approvals or rejections by the Board of YEC capital forecasts during a GRA proceeding are unlikely to significantly impact what projects YEC executes or the related staffing requirements.

The timing and nature of Board GRA reviews does not typically create opportunities for YEC to adjust its capital spending during the test years based on a final Board decision. The Board's GRA review is typically dealing with projects already fully committed and, in many cases, already implemented – and staffing for these committed projects will accordingly also have been fully committed for the GRA test years.

(f)

Year	Vacancy Rate
2018	6.05
2019	9.91
2020	9.30
2021	8.99
2022	12.62
Average	9.37
Rounded	9

REFERENCE: **Application, PDF page 28**

ISSUE: Industrial load

QUOTE: The actual industrial sales for 2021 were 91.1 GWh compared to forecast sales of 102.9 GWh [primarily due to lower VG and Hecla Yukon sales offset partially by higher Minto sales]. The actual industrial sales in 2022 were 95.2 GWh, 4.0 GWh higher than 2021 actuals. The forecast sales for the 2023 test year at 75.0 GWh reflects a decrease of 20.1 GWh from 2022 actuals due to closure of Minto industrial operations after May 2023, and the forecast sales for the 2024 test year is 69.4 GWh, reflecting a decrease of 5.7 GWh from 2023 forecast (reflects impacts of the Minto mine closure in May 2023 – VG and Hecla Yukon sales are forecast to increase in both 2023 and 2024).

QUESTION:

a) Please provide a table showing industrial sales (MWh) to each industrial customer by year for each of the years 2021 through 2024. In the case of Minto, provide a separate column showing the general service sales (MWh) for each of the years 2021 to 2024.

b) Are there any sales expected to occur for Minto beyond 2023? Please explain.

ANSWER:

(a)

Please see the table below for the requested information.

	Industrial Sales, GWh				
	Minto	Alexco/ Hecla	VG	Total Industrial	Minto - general service
	A	B	C	D=A+B+C	E
2021	44.1	10.0	37.0	91.1	
2022	47.9	9.8	37.5	95.2	
2023F	16.4	15.1	43.6	75.0	8.0
2024F	0.0	21.8	47.6	69.4	13.1

(b)

Yes – see the table provided in response to “a”. Please also see the response to YUB-YEC-1-10 (a) – (c) for additional detail.

REFERENCE: **Application, PDF page 29**

ISSUE: Actual generation

QUOTE: Actual hydro generation in 2021 was 92.5% of grid generation, reflecting higher than LTA water availability.

…

Actual hydro generation in 2022 was 91.6% of grid generation, reflecting higher than LTA water availability.

…

The 2023 and 2024 forecast firm generation, 525.5 GWh and 531.2 GWh respectively, result in forecast hydro generation at LTA supply accounting for 84.7% of grid generation in 2023 and 84.0% in 2024 and related forecast thermal generation accounting for 14.2% of grid generation in 2023 and 12.8% in 2024.

IPP renewable generation is forecast at 1.2% of forecast grid generation in 2023 and 3.2% in 2024.

QUESTION:

a) Please prepare a table listing the three main generation sources [hydro, thermal, and Independent Power Production (IPP)], and for each of the years 2021 to 2024, list the proportion of each generation source out of the total generation, comparatively showing the forecast versus actual generation outcomes (for 2023 and 2024, show only forecast proportions).

ANSWER:

(a)

The following table shows the actual generation sources for 2021 and 2022 compared to the 2021 approved forecast and 2022 business plan forecast, as well as the forecasts for 2023 and 2024. Please note that these numbers are not the long-term average hydro, IPP

and thermal generation sources used to determine revenue requirements. Long-term averages are provided in Table 2.2 of Tab 2 along with actual generation sources.

Description		2021 Approved	2021 Actual	2022 BP Forecast	2022 Actual	GRA Forecast 2023 Forecast	GRA Forecast 2024 Forecast
Total Generation		**538,726**	**533,375**	**543,005**	**537,489**	**528,644**	**534,340**
Generation by Source - MWh							
Hydro Generation		508,463	493,239	501,854	492,139	482,257	460,893
	%	94.4%	92.5%	92.4%	91.6%	91.2%	86.3%
Thermal Generation		30,260	40,134	38,762	43,398	40,285	56,636
	%	5.6%	7.5%	7.1%	8.1%	7.6%	10.6%
IPP Generation		2	2	2,389	1,952	6,102	16,811
	%	0.0%	0.0%	0.4%	0.4%	1.2%	3.1%

REFERENCE: **Application, PDF page 29**

ISSUE: Winter Peak

QUOTE: Winter peak generation on the Yukon Integrated System (including industrial load) has continued to increase in recent years, with the 2021 actual peak at 104.4 MW and the 2022 actual peak reaching 114.2 MW. Forecast YIS peak load for the test years is 119.5 MW for 2023 and 123.2 MW for 2024.

QUESTION:

a) Do winter peaks include industrial sales? Please explain.

b) When does winter peak occur? Is it in December or in the January-March time frame?

c) If the winter peak is in the January-March time frame, what was the 2023 winter peak?

ANSWER:

(a)

The peak demands provided in the quote are included in Table 2.2 of Tab 2 and include the industrial peak. However, the N-1 dependable capacity requirements and shortfall exclude industrial peak as discussed in section 2.4 of Tab 2 [please see page 2-15].

(b) and (c)

The peak demand can occur anytime during the winter season depending on weather conditions. The peak demand in 2020 occurred in January, while the peak demand in 2021 and 2022 occurred in December. January 2022 peak demand was also at the level of the December 2022 peak – in both cases the mean daily temperature was below -39 degrees.

The weather conditions in January-February 2023 were warmer than normal with the lowest mean daily temperature reaching -23.5 degrees on February 28, 2023. Therefore,

the peak demand in January-February 2023 did not reach the level of peak demand experienced in previous years. YEC expects the peak demand in December 2023 consistent with the two previous years.

REFERENCE: **Application, PDF page 30;**
Appendix A to Board Order 2018-10, PDF page 13

ISSUE: Wholesale sales

QUOTE: Application, PDF page 30:
The forecasts for 2023 and 2024 are prepared based on multi-variate regression assessments of monthly wholesales changes, the same approach used in the 2021 GRA, at normal weather conditions using the 20-year historical averages. It also reflects forecast micro-generation which reduces forecast wholesales.

Appendix A to Board Order 2018-10, PDF page 13:
Therefore, the Board directs YEC to refine its methodology to ensure its forecasts align closely with AEY's forecasts in future GRA submissions. (Similar direction was given in Appendix A to Board Order 2022-03 at PDF page 12.)

PREAMBLE: For ATCO Electric Yukon's (AEY) 2023-24 GRA, the wholesale purchases are forecast to be 349.6 GWh for 2023 and 362.7 GWh for 2024. YEC's forecast wholesale sales are 351.3 GWh for 2023 and 355.9 GWh for 2024. Although YEC provided some explanation on PDF page 30 of its Application, the reasons for the differences between the two forecasts were not provided.

QUESTION:

a) Please explain the differences between the AEY and YEC wholesales forecasts.

b) If the YEC forecast is the preferable forecast for wholesale sales, please explain why it is the superior forecast.

ANSWER:

(a) and (b)

AEY filed its 2023/24 GRA with forecast firm power purchase, excluding power purchase related to secondary sales, forecast at 349.7 GWh for 2023 and 362.6 GWh for 2024 or

an increase of 3.7% in 2024 over 2023. The AEY forecast for 2023 is 1.6 GWh or 0.5% lower than YEC's forecast, while AEY forecast for 2024 is 6.7 GWh or 1.8% higher than YEC's forecast.

YEC wholesale forecasts for 2023 and 2024 are prepared based on multi-variate regression assessments of monthly wholesales changes, the same approach used in the 2021 GRA, at normal weather conditions using the 20-year historical averages. It also reflects long-term average Fish Lake generation and forecast micro-generation which reduces forecast wholesales.

AEY's power purchase forecast involves preparing total hydro grid sales forecasts and losses based on sales forecasts developed separately by customer class and different communities, then subtracting AEY own generation [Fish Lake, standby diesel and other purchases] to get net power purchases from YEC.

AEY uses two key inputs in preparing its sales forecasts: (i) the net customer additions; and (ii) the forecast UPC. AEY 2023/24 GRA, Schedule 2.1 shows residential customer counts are forecast to increase over a two-year period by 5% [average 2.5%/year], while commercial customer counts are forecast to increase by 2.8% [average 1.4%/year].

AEY in its GRA notes that it "has maintained the same 10-year timeframe for UPC regression and normalizing HDD the Board ordered for the 2016-2017 GRA Compliance filing" and "applied the growth rates experienced over the period of 2017 to 2019, prior to the pandemic, to derive the forecast UPC for the 2023-2024 Test Period."

For YEC, YEC's forecast wholesales of 351.3 GWh for the 2023 test year and 355.9 GWh for the 2024 test year are preferable considering the following:

- YEC's forecast is based on multi-variate regression assessments of overall monthly wholesales changes at normal weather conditions using the 20-year historical averages. YEC also uses the approved long-term average Fish Lake generation as per OIC 2021-16 requirements to account for AEY generation. Absent information on a material change in conditions, this forecast approach is reasonable to retain.

- YEC's forecast annual increase in wholesales of 1.3 - 1.4% is in line with the historical averages [the average annual increase for the last five years is about 1.0%].

- The 2023 year-to-date actuals closely align with YEC's 2023 forecast [with preliminary actuals to October, the updated full-year forecast for 2023 is expected to be about 351.2 GWh versus the YEC GRA forecast of 351.3 GWh and the AEY GRA forecast of 349.7 GWh].

- The 2024 forecast for YEC shows sustained growth at 1.3% (versus 1.4% the previous year); in contrast, the AEY 2024 forecast shows a major growth increase at 3.7%, and YEC has not been able to confirm as reasonable the resulting 6.7 GWh forecast difference. The following additional evidence is noted to assist review of the 2024 primary wholesale forecasts:
    - Recent Yukon population growth forecasts[1] with growth rates of 2.1-2.2% for 2023 and 2024 are lower than the 2.5%/year residential customer growth assumed in AEY GRA forecasts [AEY assumed 5% residential customer growth over 2023/24 years].
    - The increase in microgeneration will reduce the wholesale purchases from YEC. For example, AEY's 2023/24 GRA, Schedule 3.2 shows the increase in microgeneration deliveries to the grid by about 1 GWh in 2024 compared to 2022 actuals.

The following table shows the annual average change in wholesales.

[1] See response to AEY-UCG-018(a) in AEY's 2023.24 GRA IR process which provides Yukon Economic Development Fiscal and Economic Outlook March 2023 and Yukon Bureau of Statistics Population Projections, Updated February 2023.

	Firm Wholesales, GWh	Annual Change
2018	332.3	
2019	331.5	-0.2%
2020	347.3	4.8%
2021	349.0	0.5%
2022	346.3	-0.8%
Average annual		1.0%

	YEC Forecast		AEY Forecast filed	
	GWh	Annual Change	GWh	Annual Change
2023 F	351.3	*1.4%*	349.7	*1.0%*
2024 F	355.9	*1.3%*	362.6	*3.7%*

1

REFERENCE: **Application, PDF page 31**

ISSUE: Major industrial customers

QUOTE: Minto Mine is included as an industrial customer for January-May 2023; for June-December 2023 and 2024 the load for Minto care and maintenance is included under the general service class.

QUESTION:

a) Please describe the criteria used to determine the Minto mine as a member of the general service rate class.

b) What is the forecast Minto mine load for 2024 as a general service customer?

c) How long does YEC expect the Minto mine to continue as a general service customer?

d) Does the cessation of the Minto mine operations imply that Rate Schedule 35, Low Grade Ore Processing, is no longer required? Please explain.

ANSWER:

(a) to (c)

OIC 1995/90 defines “major industrial customer” and “retail customer” as follows:

> “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.
>
> “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.

In May 2023, Minto ceased its mining operation therefore, it no longer qualified as a major industrial customer defined under OIC 1995/90 and must be served under the retail customer class.

Yukon government notes that Minto Metals Corporation abandoned the Minto mine site and Yukon government hired JDS Mining to provide emergency environmental management services at the site. It also notes that "as a regulator, the Yukon government's focus is ensuring that the environment remains protected at the Minto mine site" and it holds financial security for the site and intends to access this funding to cover the costs of the reclamation work. Currently, all electricity bills are calculated under Rate Schedule 2180, General Service Hydro, Government – Federal & Territorial and sent directly to Yukon government.

CBC News October 3, 2023 post states that based on September 28, 2023 briefing from the Department of Energy, Mines and Resources the "Yukon government is in the first phase of closing and remediating the abandoned Minto mine."

YEC does not have information on how long Minto will continue as a general service customer. The Receiver for the mine is currently trying to sell the mine. If that occurs, the mine may return to an industrial classification at some point in the future. The timing of this is not forecastable with any reasonable level of accuracy. If the Receiver is unable to sell the mine, YEC expects Minto will continue as a general service customer for the foreseeable future as it will require power for environmental purposes.

The forecast consumption for the 2024 test year under the general service customer class is 13.1 GWh.

(d)

Yes. As Minto mine ceased its mining operations this rate schedule is no longer required [please see page 4-4 of Tab 4].

REFERENCE: **Application, PDF page 32**

ISSUE: Victoria Gold and Hecla Yukon mine loads

QUOTE: Victoria Gold has significantly reduced its forecast load from what it forecast in its 2017 Power Purchase Agreement.

…

Based on the information provided by Hecla Yukon, the load forecast for 2023 is 15.1 GWh [including January-May actuals] and 21.8 GWh for 2024 reflecting an increase in mine activities starting from mid-2023.

QUESTION:

a) Are there any financial implications to Victoria Gold from reducing its forecast load from that in the 2017 Power Purchase Agreement (PPA)? Please explain.

b) How reliable is the Hecla Yukon industrial forecast? What factors affect the accuracy of the forecast?

ANSWER:

(a)

Yukon Energy is not aware if reducing its forecast load from that in the 2017 Power Purchase Agreement (PPA) level has any financial implications to Victoria Gold.

(b)

The load forecast for Hecla Yukon was provided by the customer based on information they had at the time. To date, the forecast is aligned with the actuals. For example, the January – September 2023 forecast in the GRA was 10.2 GWh compared to about 10.5 GWh actual sales for the same period.

REFERENCE: **Application, PDF page 33**

ISSUE: General service sales

QUOTE: Actual sales to the Faro Mine remediation project were 9.4 GWh in 2021 and 9.7 GWh in 2022, accounting for 32% of all general service sales. The forecasts for 2023 [including January - May actuals] and 2024 is 9.8 GWh are based on actual sales for 2022.

QUESTION:

a) When does YEC expect the Faro remediation project to end? Please explain.

ANSWER:

(a)

The Faro mine was in care and maintenance mode for approximately twenty years. Recently, the federal government initiated a remediation project. YEC's understanding is this process will take at least ten years.

REFERENCE: **Application, PDF page 34**

ISSUE: Line losses

QUOTE: Actual losses were 8.4% in 2021 and 9.0% in 2022.

QUESTION:

a) What factors cause line losses to change from 8.4 percent in 2021 to 9.0 percent in 2022?

b) Does YEC undertake any analyses to determine why line losses change from year to year? Please explain.

c) Has YEC undertaken any programs to reduce line losses? Please explain.

ANSWER:

(a) and (b)

Various factors can impact the losses (line and station losses) and the fluctuations in losses year-over-year, and YEC has not undertaken any analyses to determine why losses change year to year, or what specifically caused line losses to increase from 8.4% in 2021 to 9.0% in 2022.

Notwithstanding the above, it is understood that the most common variable affecting line losses is the distance of the generator from customers or the load centre [more power is lost the further it travels]. Looking at Tables 2.1 and 2.2. of Tab 2, the overall grid generation load was reasonably similar in 2021 and 2022, with approximate 1% growth by 2022. However, the portion of this grid load and the total generation supplied from generation facilities in Whitehorse (hydro, diesel and LNG) declined from 49.2% (262.4 GWh) in 2021 to 47.1% (253.0 GWh) in 2022, indicating greater reliance on generation further from the main Whitehorse load centre. Table 2.2 shows notable increases in 2022 generation from Mayo hydro, and Faro diesel.

(c)

Yukon Energy has not done any changes to the transmission system to reduce system losses. Any such program would require a muti-million-dollar project with a complete business case. In the next Resource Plan, Yukon Energy will be reviewing system losses and options for potential savings.

REFERENCE: **Application, PDF page 35**

ISSUE: Integrated grid hydro generation - IPPs

QUOTE: In addition, Table 2.2 shows the forecast LTA IPP generation of 6.1 GWh for 2023 and 16.8 GWh for 2024.

QUESTION:

a) Please provide the basis for a long-term average (LTA) IPP generation forecast for each of the years 2023 and 2024.

ANSWER:

(a)

The IPP supply forecasts for the 2023 and 2024 test years are based on the expected delivery from the existing and new IPP generations. The following table shows the forecast IPP generation for 2023 and 2024 by source. The 2023 forecast for three existing IPPs reflects actuals for January-May, and forecast for June-December.

GWh	Expected In Service Date as per GRA	Forecast for 2023	Forecast for 2024
Solvest/ North Klondike	In service	1.51	1.63
Nomad (Mount Sima)	In service	0.22	0.24
KDO Dawson Dome Road	In service	0.26	0.25
Sunergy 2 MW solar	Jul-23	1.13	2.70
Arctic Pharm 2MW solar	Aug-23	1.05	3.63
Haeckel Hill West 2 MW wind	Oct-23	0.99	3.95
Haeckel Hill East 2 MW wind	Oct-23	0.94	3.75
CTMC 2 MW Solar	Sep-24	0.00	0.62
NNDC 2 MW Solar	Dec-24	0.00	0.01
NNDC 2 MW Solar	Dec-24	0.00	0.01
250 kW Solar	Dec-24	0.00	0.00
		6.10	16.81

REFERENCE: **Application, PDF page 35**

ISSUE: Integrated system operation

PREAMBLE: Lines 16-21 of PDF page 35 explain the operation of the integrated system under normal operations.

QUESTION:

a) Where do IPPs place in the stacking order of generation assets? Please explain.

ANSWER:

(a)

The IPP deliveries are take or pay, therefore, they are first in the stacking order.

REFERENCE: **Application, PDF page 37**

ISSUE: Forecast thermal unit operation for maintenance

QUOTE: In addition to the thermal generation forecast to supply required firm loads, YEC is including in its forecast expenses in this Application (see Tab 3) forecast thermal unit operation for maintenance when there is no firm generation load that requires thermal generation.

QUESTION:

a) Does thermal generation for maintenance purposes displace hydro generation? That is, when thermal units are run for maintenance, how is the energy that is produced used? Please explain.

b) Does the amount of energy produced referred to in part (a) become part of the thermal energy reported in actual energy produced each year? Please explain.

ANSWER:

(a) and (b)

As illustrated in Table 3.2.1 of Tab 3, 2023 and 2024 test years include 0.198 GWh diesel for maintenance run-ups. For the test year LTA thermal calculations, it is assumed the maintenance run-ups displace hydro generation.

The maintenance run-ups are included in the total load, i.e., part of the thermal energy reported in actual energy generated each year. In the Low Water Reserve Fund (LWRF) these run-ups are then removed for the purpose of LWRF transfer calculations.

REFERENCE: **Application, PDF page 39, footnote 17**

ISSUE: LOLE

QUOTE: The WAF system had substantial hydro generation availability that is directly affected by certain transmission; the WAF system also had been trending to an increasing probability of longer outages as it expanded (particularly with expansion of residential and commercial loads and major reductions in industrial load).

QUESTION:

a) Please explain the significance of the above-noted footnote, namely the impact of increasing residential and commercial loads versus reductions in industrial loads leading to a probability of longer outages.

ANSWER:

(a)

The significance of the above-noted footnote is its long-standing support for adoption and retention of the LOLE dependable capacity planning criteria, i.e., the balance of the footnote states: "Yukon Energy therefore incorporated the LOLE approach, with recognition of transmission reliability where relevant, with its system planning criteria to better protect all of its firm customers from generation-related outages."

The above-noted footnote in the LOLE section of the Application represents key 2005 era information referenced in Section 3.3.1 of YEC's Submission for its 2006 20-Year Resource Plan to support Loss of Load Expectation (LOLE) being adopted in the recommended new two-part capacity planning criteria. At that time, expanded non-industrial loads were referencing the period after closure of the Faro mine industrial load in early 1998. The referenced segment from the 2006 20-Year Resource Plan is quoted below:

> "Yukon Energy has recently examined the LOLE approach and tested it against the operating history of its WAF system. This review has shown that the WAF system has substantial hydro generation availability that is directly affected by

> certain transmission, and that the WAF system also has been trending to an increasing probability of longer outages as it expands (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy has therefore now incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages." (Yukon Energy Corporation Submission 2006 20-Year Resource Plan, January 2006, page 3-14).

The above-noted footnote has been referenced in subsequent YEC GRAs, without material edits, in the same Tab 2 section addressing dependable capacity to meet peak demand and the LOLE capacity planning criteria (e.g., 2012-13 YEC GRA, 2017-18 YEC GRA and 2021 YEC GRA). Residential and commercial loads have continued to expand during this period, but industrial load somewhat recovered after 2006 with the Minto mine, Alexco mine and then the Victoria Gold mine load connections. The footnote is not referencing the recent reduction in industrial load after closure of the Minto mine.

REFERENCE: **Application, PDF page 40**

ISSUE: Dependable grid capacity

QUOTE: Installed YEC and AEY dependable grid capacity for the 2023/24 winter based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 148.9 MW (71.1 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of YEC diesel (reflects retirement of 2.5 MW FD1 at Faro), 5.6 MW of AEY diesel, 0.1 MW DSM and plus 36 MW diesel from rented diesel units in order to meet the N-1 criterion assessment).

Installed YEC and AEY dependable grid capacity for the 2024/25 winter based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 151.8 MW (71.1 MW of YEC hydro, 12.6 MW YEC LNG, 26.0 MW of YEC diesel [reflects retirement of 2.5 MW diesel at Dawson in 2024 and 5 MW added diesel replacements in Faro]… (Footnotes omitted.)

QUESTION:

a) Why is Fish Lake hydro excluded? Please explain.

b) For each of the years 2023 and 2024, for the retiring units, what considerations has YEC given to replace those units with larger sized units and to have the replacement units in place before retiring any units?

c) With Minto moving to a general service rate, how does this affect YEC's N-1 calculations?

d) Does Minto have on-site generation that would mitigate an N-1 condition? Please explain.

ANSWER:

(a)

Fish Lake hydro is neither dispatched nor monitored by Yukon Energy, and cannot be readily adjusted to match load conditions on a daily basis. Therefore, YEC's Integrated system peak forecast does not include peak demand associated with sales from Fish Lake hydro generation [i.e., its contribution had already been accounted for by YEC in the load forecast in terms of reduced net load].

(b)

YEC's 10-Year Renewable Electricity Plan included development of new diesel to replace retiring units, including retirements then planned for this GRA's test years. The diesel retirements are done based on assessments from Operations and Engineering staff and reflect the current conditions and reliability to provide service when required, with updates being provided on assessments as needed. Yukon Energy staff concluded that Faro diesel unit 1 with 2.5 MW has to be retired in 2023 [has been retired] and Dawson diesel units 2 and 5 with a total of 2.5 MW have to be retired in 2024. The new diesel replacements for Faro with 5 MW added capacity are expected to be in service in 2024, while Dawson diesel replacements with 6.5 MW added capacity are in 2025, with a potential in service date in 2024 [please see the response to YUB-YEC-1-25 regarding in service date for Dawson diesel replacements]. In the case of Dawson City, recent updates resulted in the new diesel units being larger at 3.25 MW than the originally planned 2.5 MW replacement units. Delays were encountered in completing these planned diesel replacements on the original planned schedule (which would have had replacement units in place before retiring units) – please see response to YUB-YEC-1-41(a) for details.

(c) and (d)

YEC did not adjust the forecast non-industrial N-1 peak demand in the test years for Minto load to reflect the recent closure of mine operations and shift to service under the general service class.

Minto has on-site thermal generation sources in case of a power outage from the grid.

REFERENCE: **Application, PDF page 45, footnote 1**

ISSUE: WH2 uprate and WH4 servomotor

QUOTE: In the 2021 GRA, the expected incremental hydraulic generation from WH2 uprate and WH4 servomotor/uprate projects was 4.2 GW.h based on a half-year impact for 2021 [7.1 GWh/year] and was manually adjusted after the model runs [please see 2021 GRA, Appendix 2.1, Table 2.1-1 note #7]. For 2023/24 GRA, YECSIM model inputs are adjusted to reflect the uprate projects and Tables 2.1-1 and 2.1-2 already reflect the incremental hydro generation. The annual expected incremental hydraulic generation is about 6.3 GW.h at 2024 load levels [overall firm generation load in 2024 is lower compared to the 2021 GRA firm load].

QUESTION:

a) For WH4, please explain why the incremental generation has been downgraded from 7.1 GWh/year to 6.3 GWh/year.

b) Do the WH2 and WH4 uprates included in LTA calculations increase the rated capacity for those units? Please explain. If so, have those increases been incorporated in the N-1 calculations?

ANSWER:

(a)

The updated incremental hydro generation from uprates reflects the forecast load conditions for the 2023 and 2024 test years and is impacted by factors such as overall lower firm generation [2024 firm generation at 531.2 GWh compared to 538.7 GWh in 2021 approved] and added new supply [IPPs].

The benefits from uprates, including energy and dependable capacity benefits, are provided in Appendix 5.1A, pages 5.1A-36 through 5.1A-39.

(b)

Yes, as indicated on page 2-14, footnote 23 in Tab 2, the dependable capacity for Whitehorse Hydro Generating Facility was increased from 27.0 MW to 27.6 MW to reflect 0.6 MW for WH2 uprate which reduces the N-1 dependable capacity shortfall [no added dependable capacity for WH4 Servomotor].

REFERENCE: **Application, PDF page 53**

ISSUE: Forecast delivered process for LNG and diesel fuels

QUOTE: Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2023 and 2024 test years is $0.4917 per litre.

…

Forecast diesel delivered prices for the 2023 and 2024 test years are $1.1043 per litre for Whitehorse, $1.1415 per litre for Faro, $1.1698 per litre in Dawson and $1.1496 per litre in Mayo, and reflect the most recent diesel prices for YEC as of May 1, 2023.

QUESTION:

a) How are the forecast fuel prices determined? What source is used to determine the forecast fuel prices?

b) How are actual fuel prices determined? Is a tender process utilized?

ANSWER:

(a) and (b)

Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility of $0.4917 per litre reflects contracted liquefaction and transportation costs for 2023 with Ferus, as well as the market price for commodity value at the time of preparation of the Application [the actual price for May 1, 2023]. It includes $2.79/GJ commodity price, $9.50/GJ liquefaction cost and $9.45/GJ transportation cost to total delivered cost of $21.74/GJ or with an energy content of 0.02262 GJ/litre equals $0.4917 per litre [$21.74/GJ x 0.02262]. The contract for liquefaction and transportation costs with Ferus was based on the competitive tender process completed in 2019 that covered four supply years commencing in 2020. The contract has been amended in 2023, including an extension through 2024. Based on the extension agreement, the liquefaction cost is $9.50/GJ and the transportation cost is $9.45/GJ for the remainder of 2023. As per the extension agreement, the liquefaction and transportation costs for 2024 will be updated using CPI adjustment

[December 2023 CPI over December 2022 CPI]. For the GRA purposes, YEC used $9.50/GJ liquefaction and $9.45/GJ transportation costs for both 2023 and 2024 test years. Commodity price fluctuates based on an established market reference (NGX Alberta).

Forecast diesel delivered prices of $1.1043 per litre for Whitehorse, $1.1415 per litre for Faro, $1.1698 per litre in Dawson and $1.1496 per litre in Mayo reflect actual diesel prices for YEC as of May 1, 2023 based on pricing by diesel fuel provider North 60 Petro Ltd that reflects Edmonton Terminal Unbranded Rack prices. The actual prices each month are updated based on monthly fuel prices provided by the suppliers [Mackenzie Petroleum for Dawson and North 60 Petro Ltd for other locations]. Yukon Energy plans to tender in 2024 for Whitehorse diesel fuel delivery [Whitehorse diesel fuel consumption is about 65% of total diesel fuel consumption]. YEC files quarterly diesel price information with the YUB as directed in Board Order 1993-8.

REFERENCE: **Application, PDF page 58**

ISSUE: Non-fuel O&M - FTEs and overtime

QUOTE: … The increase in employee complement has resulted in a significant decrease in forecast overtime costs as a percent of total labour costs for 2023 and 2024 as compared to the overtime for 2021 and 2022 actual years.[2] Increased employee complement is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. YEC has made a conscious effort to limit increases only to those areas where required as reviewed below.

[2] The overtime as percentage of total salaries and wages has reduced from 6.14% actual in 2021 to 5.09% actual in 2022, and forecast to reduce to 4.69% in 2023 and 3.93% in 2024 [2021 approved was 4.72%].

QUESTION:

a) Please provide the dollars attributed to the calculation of overtime as a percentage of total labour costs noted in footnote 2.

b) Please give specific examples of where an FTE position was filled and thereby replaced the use of an outside consultant or contractor.

c) Please provide the forecast overtime cost reduction for 2023 and 2024 that is to result from YEC's increase in employee complement.

ANSWER:

(a)

The dollars attributed to the calculation of overtime as a percentage of total labour costs noted in footnote 2 are as follows:

$000	2021 GRA	2021	2022	2023	2024
Overtime	742	971	802	866	775
Gross Salary	15,719	15,807	15,753	18,489	19,695
%	4.72%	6.14%	5.09%	4.69%	3.93%

(b)

Specific examples are included below, however, YEC wants to clarify that adding FTE positions is not always the best option as compared to hiring an outside consultant or contractor. The decision depends on many factors, including but not limited to market conditions (can a qualified employee be found) and workload (can the employee be kept busy). There are many situations where hiring an outside consultant or contractor is the better option. Furthermore, it must be stressed that YEC workload exceeds the ability to get work done, whether through FTE positions or outside consultants or contractors. The work needs to get done; it is just a matter of who does it. It can be argued that all FTE positions offset the need for outside consultants or contractors.

Specific example #1: In 2022, YEC created a Regulatory Planner position. This position is responsible for research and analysis services in support of regulatory filings. This position has greatly reduced the use of outside consultants with all regulatory filings, including this Application.

Specific example #2: Since YEC's 2021 GRA, there has been a focus within YEC to increase the capacity of the Engineering department to enable itself to deliver growth in workload due to an unprecedented capital program resulting from demands driven by adaptation for climate change, expanding infrastructure to meet increased electricity demand driven by population growth, electrification and transition to a net zero carbon economy, and revitalization of aging infrastructure. Specifically, YEC added a Director of Capital Projects, a Director of Engineering and a Junior Project Manager. Without these positions being filled internally, YEC would have had to hire outside consultants or contractors to fulfill the workload.

(c)

YEC cannot provide a useful estimate of forecast overtime reduction for each test year resulting from YEC's increase in employee complement.

Based on the premise that the work needs to get done, if YEC did not add FTE's or hire outside consultants or contractors, there would be a significant increase in overtime hours and costs. Each full-time position is allocated 2080 regular hours per year, so if YEC did not add FTE's but maintained the work completion, all these hours could then be considered potential overtime for each FTE not filled. In reality, however, the overtime costs would be constrained due to safety reasons as YEC policies have a maximum number of hours an employee can work in a day without rest. Therefore, the ultimate result would be a combination of a significant increase in overtime hours for existing employees, potential increased use of consultants, and prioritization of work so that not all work is completed.

ISSUE: YEC planning horizon

QUESTION:

a) From a planning perspective:
   i. What time range does YEC define as “short term”?
   ii. What time range does YEC define as “long term”?
   iii. Does YEC define any time range between long term and short term? Please explain.

ANSWER:

(a)

From a planning perspective, YEC’s resource planning department defines short-term as delivering capacity under ten years. From a planning perspective, YEC’s resource planning department defines long-term as delivering capacity beyond ten years.

REFERENCE: **Application, PDF pages 59-63**

ISSUE: Non-fuel O&M - 2023-2024 FTE hiring

QUESTION:

a) Please confirm whether YEC has commenced the hiring process for the 1.00 FTE position for Government Relations as of the date of filing the response to this IR.

b) Please confirm if the 0.25 FTE position for Finance, Procurement & Information Technology has been filled as of the date of filing the response to this IR.

c) Please provide the length of time the term will last for the 1.00 FTE position for Regulatory Projects Financial Analysis which was filled in 2023. How has this length of time been factored into this Application?

d) Please confirm if the 1.00 FTE position for Junior Project Manager has been filled as of the date of filing the response to this IR.

e) Please confirm whether YEC has commenced the hiring process for the 1.00 FTE position within Engineering Services for “new full-time positions and new co-op positions” as of the date of filing the response to this IR. Please also clarify how many positions there are and the related FTE allocation to each.

f) Are the Engineering Services co-op positions referred to in part (e) expected to stay on as permanent full-time employees after the co-op term ends? If so, how has this been factored into this Application?

g) Please provide a summary of all 2020, 2021, and 2022 actual and 2023 and 2024 forecast co-op positions.

ANSWER:

(a)

Yes and No. YEC commenced hiring the Manager, Community Relations and offered the position to an individual and the offer was accepted. However, subsequently, the acceptance has been retracted. YEC has not re-commenced the hiring process at this time.

(b)

Confirmed.

(c)

The Regulatory Projects Financial Analyst position was filled in 2023 for a two-year term. As the term covers each of the years 2023 and 2024, the position is reflected as a 1.0 FTE in 2023 and a 1.0 FTE in 2024.

(d)

Confirmed.

(e)

As detailed in Table 3.4.1, there are eight incremental Engineering Services positions. Each are to be filled by one person except for the co-op positions which is planned for one person at one-third of an FTE and another person at two-thirds of an FTE. The hiring status of each of the positions was provided on pages 3-14 and 3-15 of the Application, which shows that all positions were filled at the time of filing the Application except for the Junior Project Manager and the co-op positions. Subsequent to filing, the Junior Project Manager position has also been filled.

Subsequent to filing, it became apparent to YEC that priorities had shifted and there was a need for more internal engineering resources relating to transmission and distribution. As a result, YEC replaced the 1.0 FTE co-op positions with a 1.0 FTE position for Manager, Transmission & Distribution in the Engineering department. This position has been filled.

(f)

As stated in part (e) to this response, the co-op positions have been replaced by the Manager, Transmission & Distribution position. This does not impact the FTE calculation in this Application. The co-op positions reflected a 1.0 FTE in 2024; however, this has been replaced with a 1.0 FTE for the Manager, Transmission & Distribution position in 2024.

(g)

There were no co-op positions in 2020 through 2023. As stated in parts (e) and (f) to this response, the co-op positions forecast for 2024 have been replaced by the Manager, Transmission & Distribution position.

REFERENCE: **Application, PDF page 64**

ISSUE: Diesel generator rentals

QUOTE: The 2021 GRA forecast requirement for 1.8 MW diesel rental units was 15 units as approved in 2021, excluding spares; the same 15 units was required in 2022 (i.e., winter 2022/23), and 20 units is forecast for both winter 2023/24 and winter 2024/25, excluding spares (see Section 2.4 of Tab 2).

QUESTION:

a) How many spare rented diesel generation units does YEC forecast it will acquire for each of the test years?

b) How does YEC account for the costs of any spare diesel rental generation units?

c) Do the rented diesel generation units remain in locations determined by YEC in Yukon each year until the lease is not renewed, or are they removed from these locations after the winter peak season? Please explain.

d) Please provide the maintenance costs for the rented diesel generation units that YEC has incurred each year since YEC commenced renting diesel generation units.

e) Please provide the internal costs YEC has incurred for operating the rented diesel generation units for each year since YEC commenced renting diesel generation units.

f) Please provide all evidence demonstrating competitive supply for YEC's diesel rental costs — i.e., the process of how the rented diesel generator units were acquired.

ANSWER:

(a)

Two spare units, one in Whitehorse and one in Faro/Mayo [for 2022/23 winter the spare unit was in Faro, for 2023/24 and 2024/25 winter seasons in Mayo], in each test year. The costs related to spare units are removed from revenue requirements.

(b)

The rental contracts do not specifically separate the cost related to the spare units. The equipment rental costs for one generator and one transformer, preventative maintenance, start-up and commissioning and transportation costs related to one spare unit from each location are removed from the total rental costs included in the revenue requirements. The share of preventative maintenance, start-up and commissioning and transportation costs are determined as the total cost for each location divided by the number of units.

	Cost of Spare Units, $000
Whitehorse	
Generators	127.8
Transformers	49.0
Preventative Maintenance (usage charges)	7.0
Start-up and Commissioning	6.2
Transportation Costs	92.9
Subtotal	**282.9**
Mayo	
Generators	194.0
Transformers	58.5
Preventative Maintenance (usage charges)	7.0
Start-up and Commissioning	3.7
Transportation Costs	59.8
Subtotal	**322.9**

(c)

The diesel units are returned when the rental contract ends. However, if the rental units are not required in other places, and the supplier and YEC can agree, the units can remain until the next winter season. For example, in 2022 and 2023 some of the units remained in Whitehorse and Faro and YEC paid "stand down fees" for six months [May through October].

Please see the response to YUB-YEC-1-1 a) - c) that shows stand down fees that reduce costs such as transportation, connection and disconnection costs.

(d)

The contractor maintenance costs are included in the rental cost. YEC has incurred the following maintenance costs for operation of the rented diesel generation units.

2018	2019	2020	2021	2022	2023
$4,900	$9,900	$11,400	$1,100	$7,900	$1,900

(e)

YEC does not incur incremental labour costs for operating the rented diesel generation units.

(f)

In 2018, YEC ran a one-year public competitive tender process for 6 – 2 MW diesel generators and received two bids [Trinity Power for $1.860 million and Finning Canada for $1.558 million] and the contract was awarded to Finning.

In 2019, YEC ran a tender for a three-year contract for 8 – 2 MW diesel generators and received three bids [United Rentals for $3.706 million and Finning Canada for $1.913 million, one was non-compliant and was excluded from pricing review] and the contract was awarded to Finning.

Based on the results of these two tenders and subsequent market scans (2022), YEC determined that extending the contracts with Finning was the best sourcing option. YEC

is in the process of testing the market again in late 2023. YEC is working through a tender process for this to: (1) qualify potential vendors; and then (2) establish a longer-term contract.

REFERENCE: **Application, PDF page 65**

ISSUE: Additional dependable capacity

QUOTE: Additional dependable capacity is forecast to be commissioned during 2024 (i.e., the Battery Energy Storage System (BESS) project, plus 6.5 MW of new diesel at Dawson) – however, pending confirmation before approximately June 2024 of ability to rely on any such new facilities during all of winter 2024/25, YEC must retain diesel rentals as currently planned. New capital facilities to be commissioned in 2024, such as BESS and Dawson diesel replacement, will be included in the 2023/24 GRA revenue requirement rate base only to the extent that diesel rentals for winter 2023/24 and 2024/25 can be reduced. (Underlining added.)

QUESTION:

a) Please clarify what YEC means in the above quote, particularly the underlined portion.

b) The above quote seems to state that YEC will change its revenue requirement after the Board renders its decision on this Application. Please explain if and how YEC intends to change its revenue requirement after the Board has made a decision.

ANSWER:

(a) and (b)

The above quote is intended to clarify that YEC is only asking the Board to include one supply source in YEC's 2024 GRA revenue requirement (i.e., rented diesel or new BESS or new Dawson diesel capital facilities) for the corresponding required dependable capacity.

Section 2.4 of the Application shows winter 2024/25 dependable capacity requiring 36 MW (20 units) of diesel rentals, excluding spares – and that this rental diesel forecast assumes

that neither the BESS (7.2 MW dependable capacity) nor any Dawson new diesel capacity (6.5 MW for 2 x 3.25 MW units) are being relied on to provide dependable capacity for winter 2024/25. The forecast 2024 test year revenue requirement in the Application includes costs for the diesel rental 36 MW; in contrast, capital costs for the BESS and Dawson new diesels remain in WIP for the Application 2024 test year revenue requirement, notwithstanding that both of these new dependable capacity capital facilities are forecast to be commissioned during 2024.

The above quote acknowledges the possibility that the BESS and/or new Dawson diesel dependable capacity being commissioned in 2024 might be confirmed as being reliable during all of winter 2024/25, and that this confirmation might occur soon enough in 2024 (i.e., before approximately June 2024) to enable cancellation of approximately equivalent diesel rental capacity. Otherwise, the quote notes that YEC must retain diesel rentals in winter 2024/25 as currently planned.

If YEC can reduce its requirement forecast for rented diesels prior to the Board's GRA hearing due to confirmed BESS and/or new Dawson diesels, YEC will propose to the Board that the revenue requirement for the 2024 test year be adjusted to exclude the removed diesel rentals and include the commissioned additional dependable capacity that enabled the reduction of diesel rentals.

To be clear, no matter how events unfold in 2024, YEC will not change (and did not propose to change) its revenue requirement for the 2024 test year (i.e., the regulated forecast revenue requirement used to set approved rates) after the Board's hearing has concluded evidence for this proceeding, let alone after the Board's decision on this Application.

Please see response to YUB-YEC-1-39 (a-d) for additional detail relating to the above.

REFERENCE: **Application, PDF page 76; Appendix A to Board Order 2022-03, par. 368**

ISSUE: LWRF

QUOTE: Application, PDF page 76:
Board Order 2022-03 (Appendix A, para 368) directed YEC, on a go-forward basis, to treat the balance in the LWRF as an offset to rate base. In support of this change in rate base determination as proposed by YEC based on prior GRA approvals, the Board referenced Board Order 1992-1 directing the treatment of low water reserve funds as an offset to rate base. The net impact of this change increased YEC's 2021 mid-year rate base, and reduced YEC's 2022 mid-year rate base. (Footnote omitted.)

Appendix A to Board Order 2022-03, par. 368:
Given at least one past Board Order directing the treatment of low water reserve funds as an offset to rate base, the Board directs YEC, on a go-forward basis, to treat the balance in the LWRF as an offset to rate base. The Board directs YEC to reflect this change in its compliance filing.

QUESTION:

a) Please restate YEC's financial schedules to reflect the treatment of the balance in the Low Water Reserve Fund (LWRF) as an offset to rate base as directed in Board Order 2022-03.

b) Please provide the net change in YEC's requested revenue requirement for each of the test years based on the response to part (a).

ANSWER:

(a) and (b)

Appendix A to Board Order 2022-03 (para. 368) directed YEC in its 2021 compliance filing "to treat the balance in the LWRF as an offset to rate base". In order to comply with the

Board Order, YEC's 2021 GRA compliance filing, as approved, adjusted the 2020 and 2021 year end rate bases with offsets for LWRF actual year end balances - 2020 ending balance of - $4.272 million and 2021 ending balance of $2.782 million – the LWRF offset to 2021 mid-year rate base consequently equaled negative $0.745 million.

YEC currently has available the actual 2022 year end LWRF balance of $9.895 million as approved by Board Order 2023-11. In order to treat the LWRF balance as an offset to the 2023 and 2024 test year rate bases as requested in this IR, it is necessary to forecast the LWRF year-end balance for 2023 and 2024 test years. While YEC is complying with the YUB request for this IR presentation, this, however, would be inconsistent with the OIC 2021/16 requirements considering the following:

- The OIC 2021/16 requires the Board to determine YEC's forecast fuel costs for a fiscal year, for the purpose of setting YEC's rates, based on long-term averages. Accordingly, the 2023 and 2024 test year revenue requirements are set based on long-term average thermal generation fuel costs.

- As LWRF deals with the variance between long-term average and actual thermal generation, there should not be any LWRF transfer forecasts for the 2023 and 2024 test years as part of the rate setting process. The inclusion of any LWRF transfers for the 2023 and 2024 test years would contradict the OIC requirements [i.e., the revenue requirements would not be set based on long-term averages].

- Consequently, the inclusion of forecast estimated 2023 and 2024 LWRF transfers as an offset to the rate base for the 2023 and 2024 test years would result in a reduction of the revenue requirements which would contradict the OIC requirements as the rates would be lower than the rates that are set based on long-term averages everything else being equal.

In order to be responsive to the YUB request in this IR, YEC has calculated 2023 and 2024 LWRF estimates based on available information as follows:

- 2023 year-end LWRF forecast balance of $14.113 million reflects an estimated $4.2 million transfer from YEC to LWRF [based on Jan-Oct actuals and Nov-Dec forecasts].
    - The forecast 2023 mid-year LWRF balance is then $12.004 million.
    - This would be the offset to 2023 mid-year rate base.

- 2024 year-end LWRF forecast balance of $16.297 million reflects an estimated $2.2 million transfer from YEC to LWRF [based on generation forecasts from Table 2.2]. The LWRF balance exceeds the +/- $16 million threshold – this response therefore assumes the LWRF year end is capped at $16 million for the purpose of complying with the Board Order 2023-11 directed offset to rate base at 2024 year end (actual refunds would be provided in 2025 after 2024 year-end approvals).

    - The 2024 mid-year LWRF balance is then $15.057 million.
    - This would be applied as offset to 2024 mid-year rate base.

The following table shows the net change in revenue requirements and revenue shortfall for both test years:

- The revenue requirement and revenue shortfall for the 2023 test year is reduced by $0.455 million [2023 change is lower than the 2024 test year as it already reflects half of the LWRF balance in the 2023 mid-year rate base - 2023 mid-year balance uses the 2022 year-end rate base which included LWRF balance].

- The revenue requirement and revenue shortfall for the 2024 test year is reduced by $0.910 million, of which $0.315 million reduction is due to the forecast increase of the LWRF balance for 2023 and 2024 over the 2022 year end approved actual of $9.895 million.

- The above results in an overall rate increase of 13.27% compared to 14.11% as filed.

$000	Application as Filed		YUB-YEC-1-26 [LWRF included as an offset to rate base]		Change	
	2023	2024	2023	2024	2023	2024
Revenue Requirement	$81,440	$90,425	$80,985	$89,515	-$455	-$910
Less: Other Revenues	$394	$394	$394	$394	$0	$0
Less: Secondary Sales	$358	$358	$358	$358	$0	$0
Revenue Required from Firm Rates	$80,688	$89,673	$80,233	$88,763	-$455	-$910
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$74,021	$74,353	$74,021	$74,353	$0	$0
Additional Firm Rate Revenues Required	$6,667	$15,320	$6,212	$14,410	-$455	-$910

- It is noted that the above results show that compliance with Board Order 2023-03 results in changes in revenue requirements that are linked to forecast renewable generation varying from the LTA forecasts directed by OIC 2021-16.

Please see YUB-YEC-1-26 Attachment 1 for Tab 7 schedules with LWRF balance included as an offset to the rate base for both 2023 and 2024 test years based on the forecasts provided above.

Please also see the responses to YUB-YEC-1-27 and YUB-YEC-1-28.

Yukon Energy Corporation 2023/24 GRA

YUB-YEC-1-26 Attachment 1

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Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Property, Plant and Equipment**						
2	Year end balance	S.3 L.4	728,282	691,598	735,254	813,146	877,301
	Deduct:						
3	Accumulated depreciation (note 1)	S.3 L.8	198,403	198,509	211,205	223,380	239,086
4	Construction-in-progress	S.3 L.12	40,572	3,808	33,638	81,644	100,578
5	Disallowed assets	S.3 L.11	12,152	14,406	13,688	676	632
6	Miscellaneous reserves	S.3 L.17	7,609	7,623	13,283	16,192	17,751
7	Total deductions		258,737	224,346	271,814	321,892	358,046
	Add:						
8	Deferred Costs and Intangible Assets (note 2)	S.3 L.83	44,229	42,173	43,681	55,630	65,696
9	Less: Deferred Costs and Intangibles in Progress	S.3 L.84	30,489	29,343	28,260	25,707	38,049
10	Total additions		13,739	12,829	15,421	29,923	27,647
	Net plant in Service						
11	Current year-end balance	S.3 L.86	483,285	480,081	478,861	521,177	546,902
12	Previous year-end balance		486,567	461,515	480,081	478,861	521,177
13	Mid-year balance		484,926	470,798	479,471	500,019	534,039
14	Working capital	S.2 L.8	7,092	6,925	7,581	8,269	8,581
15	**Gross Rate Base**		492,018	477,723	487,052	508,288	542,620
	Deduct:						
	Contributions for extensions (PP&E)						
16	Current year-end balance		254,348	235,303	247,475	259,283	264,183
17	Contributions in WIP		20,776	1,386	12,788	16,500	21,000
18	Current year-end balance in-service		233,571	233,918	234,687	242,783	243,183
19	Accumulated amortization of contributions		48,722	48,401	53,074	58,503	64,127
20	Net current year-end balance in-service		184,849	185,517	181,613	184,280	179,056
21	Previous year-end balance		180,255	168,025	185,517	181,613	184,280
22	Mid-year balance		182,552	176,771	183,565	182,947	181,668
23	**Net Rate Base**	S.5 L.1	309,466	300,951	303,487	325,341	360,953

Note 1: Including Reserve for Future Removal and Site Restoration

Note 2: Please see details in Schedule 3. In the 2021 GRA Regulatory Deferral Account balance was provided as a separate line item, now included with other deferral accounts with a detailed breakdown in Schedule 3. Balances are net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Operating and maintenance	S.5 L.5	43,211	40,096	44,641	50,017	53,178
2	Taxes other than income	S.5 L.6	750	739	743	758	777
3	Non-allowable expenses	S.5 L.12	(120)	(117)	(121)	(120)	(120)
4	Cash operating expenses		43,841	40,718	45,263	50,655	53,835
5	27/365		3,243	3,012	3,348	3,747	3,982
6	Inventory (three year average)		4,014	4,156	4,464	4,683	4,817
7	GST Impact on working capital	S.2A L.11	(165)	(243)	(231)	(162)	(218)
8	Working capital	S.1 L.14	7,092	6,925	7,581	8,269	8,581

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Expenses subject to GST		96,059	50,415	69,788	118,093	110,174
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		4,803	2,521	3,489	5,905	5,509
4	Day Factor		14	14	14	14	14
5	Recoverable portion of GST impact		184	97	134	226	211
6	Revenue subject to GST		72,825	70,916	76,032	80,985	89,515
7	GST blended rate		5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		3,641	3,546	3,802	4,049	4,476
9	Day factor		35	35	35	35	35
10	Payable portion of GST impact		349	340	365	388	429
11	Net impact of GST on working capital	S.2 L.7	(165)	(243)	(231)	(162)	(218)

Yukon Energy Corporation
Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
($000s)

Schedule 3
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
	Property, Plant and Equipment						
1	Balance at beginning of year		672,467	667,962	691,598	735,254	813,146
2	Net Increases to PPE (Table 5.1)		57,152	26,668	44,506	80,430	64,154
3	Retirements, disposals and adjustments		(1,337)	(3,032)	(850)	(2,538)	-
4	Balance at end of year	S.1 L.2	728,282	691,598	735,254	813,146	877,301
	Accumulated depreciation						
5	Balance at beginning of year		185,384	184,570	198,509	211,205	223,380
6	Depreciation expense	S.6 L.7	13,436	14,926	13,308	14,300	15,706
7	Retirements, disposals and adjustments		(417)	(987)	(613)	(2,125)	-
8	Balance at end of year	S.1 L.3	198,403	198,509	211,205	223,380	239,086
	Deductions from PP&E:						
9	Disallowed assets		13,192	15,166	15,166	1,152	1,152
10	Accum. Disallowed depreciation		(1,039)	(760)	(1,478)	(476)	(521)
11	Net Disallowed	S.1 L.5	12,152	14,406	13,688	676	632
12	Construction-in-progress	S.1 L.4	40,572	3,808	33,638	81,644	100,578
	Miscellaneous Reserves						
13	Fire Insurance Reserve		3,918	3,918	3,656	3,394	3,132
14	LWRF		2,744	2,744	9,895	14,113	16,000
15	Reserve for Injuries and Damages		(1,843)	(1,777)	(2,997)	(3,281)	(3,347)
16	Reserve for Future Removal and Site Restoration		2,790	2,738	2,729	1,966	1,966
17	Total Miscellaneous Reserves	S.1 L.6	7,609	7,623	13,283	16,192	17,751
18	Total Deductions		60,333	25,837	60,609	98,512	118,960
19	Net Property, Plant and Equipment for Rate Base		469,545	467,251	463,440	491,254	519,255
	Add:						
20	Deferred study costs and Intangible assets (net of contributions)						
21	Feasibility Studies						
22	Opening balance		16,798	15,974	15,149	13,765	13,276
23	Additions		6,686	1,343	107	560	1,500
24	Amortization		(2,274)	(2,168)	(1,491)	(1,049)	(2,268)
25	Year-end balance		21,210	15,149	13,765	13,276	12,508
26	Feasibility Studies WIP			10,343	10,040	190	785
27	Relicensing						
28	Opening balance		11,882	12,485	13,884	17,089	27,135
29	Additions		1,745	1,738	3,544	10,866	6,110
30	Amortization		(339)	(339)	(339)	(820)	(928)
31	Year-end balance		13,288	13,884	17,089	27,135	32,318
32	Relicensing WIP			13,425	13,066	23,356	29,053
33	Dam Safety						
34	Opening balance		203	203	229	178	127
35	Additions		80	81	-	-	-
36	Amortization		(64)	(55)	(51)	(51)	(51)
37	Year-end balance		219	229	178	127	76
38	Dam Safety WIP			-	-	-	-
39	Vegetation Management Deferral						
40	Opening balance		1,329	1,329	1,108	886	665
41	Additions		-	-	-	-	-
42	Amortization		(222)	(222)	(222)	(222)	(222)
43	Year-end balance		1,108	1,108	886	665	443
44	Vegetation Management Deferral WIP			-	-	-	-
45	Intangibles						
46	Opening balance		5,076	4,952	5,012	4,582	9,840
47	Additions		1,095	926	359	5,976	4,830
48	Amortization		(729)	(866)	(789)	(718)	(1,281)
49	Year-end balance		5,442	5,012	4,582	9,840	13,389
50	Intangibles WIP			25	106	175	4,625
51	DSM						
52	Opening balance		876	720	623	736	1,857
53	Additions		120	(4)	208	1,250	1,160
54	Amortization		(161)	(93)	(94)	(130)	(255)
55	Year-end balance		835	623	736	1,857	2,762
56	DSM WIP			145	-	-	-
57	Hearing Reserve						
58	Opening balance		63	182	227	881	1,016
59	Additions		-	101	903	386	-
60	Amortization		(55)	(55)	(250)	(250)	(250)
61	Year-end balance		8	227	881	1,016	766
62	Other Regulatory						
63	Opening balance		1,517	4,793	5,942	5,601	1,751
64	Additions		821	815	(390)	(3,909)	1,600
65	Amortization		(274)	278	(201)	(191)	(131)
66	Hearing Reserve Amortization tranfer		55	55	250	250	250
67	Year-end balance		2,119	5,942	5,601	1,751	3,470
68	Regulatory WIP			7,960	6,206	2,274	3,874
69	IPP Cost Deferral						
70	Opening balance			-	-	26	26
71	Additions			-	26	-	-
72	Amortization			-	-	-	-
73	Year-end balance		-	-	26	26	26
74	Defined Benefit Pension Deferral Account						
75	Opening balance			-	-	(62)	(62)
76	Additions			-	(62)	-	-
77	Amortization			-	-	-	-
78	Year-end balance		-	-	(62)	(62)	(62)
79	Total Deferred Costs and Intangible Assets						
80	Opening balance		37,744	40,638	42,173	43,681	55,630
81	Additions		10,547	5,000	4,695	15,129	15,200
82	Amortization		(4,063)	(3,465)	(3,187)	(3,180)	(5,134)
83	Year-end balance	S.1 L.8	44,229	42,173	43,681	55,630	65,696
84	Less: Deferred Costs and Intangible Assets in Progress	S.1 L.9	30,489	29,343	28,260	25,707	38,049
85	Total Net Deferred Costs and Intangible Assets for Rate Base		13,739	12,829	15,421	29,923	27,647
86	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	483,285	480,081	478,861	521,177	546,902

Notes:
1. In 2021 and 2022 the PAMMS project was under regulatory and transferred to Intangibles in 2023.

Yukon Energy Corporation Schedule 3A - 2023

Calculation of Depreciation Expense for 2023 YUB-YEC-1-26 Attachment 1

$000

Description	Cost at 2022 Year End	2023 Additions	2023 Disposals/ Adjustments	Cost at 2023 Year End	Proposed Depreciation Rate (Years)	Forecast 2023
Land						
Hydraulic Production	444.9	0.0		444.9	0	0.0
Diesel Production	27.7	0.0		27.7	0	0.0
Main Transmission Facilities	576.9	0.0		576.9	0	0.0
Distribution System	17.8	0.0		17.8	0	0.0
General Plant	548.0	0.0		548.0	0	0.0
Rights	128.8	0.0	1.6	127.2	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,744.0**	**0.0**	**1.6**	**1,742.4**		**1.6**
Hydro Plant						
Structures and Improvements	52,844.5	1,969.4		54,813.8	72	731.3
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,412.1	500.2		167,912.3	103	1,844.9
Hydro, Dams wtwys Twin Assets	6,711.4			6,711.4		0.0
Overhaul	9,053.0	2,461.0		11,514.0	10	905.3
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	325.4
Accessory Electric Equipment	27,366.3	0.0		27,366.3	40	725.1
Accessory Digital Equipment	851.2	0.0		851.2	20	42.6
Misc Power Plant Equipment	11,691.4	1,470.8		13,162.2	30	389.7
Fencing	107.1	0.0		107.1	30	2.7
Depreciation Study Differences						-140.3
Total Hydro Plant	**314,538.5**	**6,401.3**	**0.0**	**320,939.8**		**5,083.5**
Diesel Production						
Structures and Improvements	1,562.4	0.0		1,562.4	72	21.7
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.5	0.1		2,735.6	40	45.0
Generating Equipment and Prime	14,202.3	4,300.0	1,996.1	16,506.2	40	283.9
Overhaul	2,962.8	0.0		2,962.8	5	0.0
Minto Generating Equipment	243.5	0.0		243.5	12	0.0
Accessory Electric Equipment	9,428.1	51.9	541.9	8,938.0	45	208.4
Misc Power Plant Equipment	1,874.4	0.0		1,874.4	30	60.4
Depreciation Study Differences						-74.4
Total Diesel Production	**33,483.6**	**4,352.0**	**2,538.0**	**35,297.6**		**553.7**
Wind Turbine						
Wind Turbine	0.0	0.0		0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Main Transmission Facilities						
Poles and Fixtures	82,825.5	1,963.3		84,788.8	65	1,274.2
Brushing	16,756.3	0.0		16,756.3	60	263.2
Survey Costs	4,297.2	0.0		4,297.2	60	67.9
Overhead Conductors / Poles	20,202.9	0.0		20,202.9	60	313.2
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.1
Substation Equipment	62,928.1	2,179.4		65,107.5	54	1,278.4
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	890.7
STATCOM - VGC Group - Gold Mine	13,991.5	0.0		13,991.5	10	1,399.1
Other - VGC Group - Gold Mine	848.0	0.0		848.0	10	84.8
Substation Buildings	8,907.6	0.0		8,907.6	55	28.1
Substation Fences	274.5	0.0		274.5	30	7.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**221,998.2**	**4,142.6**	**0.0**	**226,140.8**		**5,531.2**
Sub Transmission Lines						
Poles and Fixtures	4,584.0	0.0		4,584.0	65	68.5
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	13.3
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	2.2
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	0.5
Overhead Conductors	1,837.9	0.0		1,837.9	60	24.3
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	4.6
Substation Equipment	8,092.8	0.0		8,092.8	54	149.9
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	38.8
Depreciation Study Differences						-46.0
Total Sub Transmission Lines	**25,840.9**	**0.0**	**0.0**	**25,840.9**		**258.5**
Distribution System						
Poles and Fixtures	10,354.7	7,432.4		17,787.1	40	246.6
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	18.9
Overhead conductors - Poles	285.8	0.0		285.8	50	5.4
Overhead Costs	2,119.5	0.0		2,119.5	40	53.0

Yukon Energy Corporation Schedule 3A - 2023

Calculation of Depreciation Expense for 2023 YUB-YEC-1-26 Attachment 1

$000

Description	Cost at 2022 Year End	2023 Additions	2023 Disposals/ Adjustments	Cost at 2023 Year End	Proposed Depreciation Rate (Years)	Forecast 2023
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	12.4
Meter Equipment	288.4	0.0		288.4	16	11.6
Substation Equipment	1,287.2	616.3		1,903.4	40	30.3
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.0
Street Lights	603.4	0.0		603.4	40	14.1
Line Transformers	4,042.5	0.0		4,042.5	35	111.2
Sentinel Lights	36.4	0.0		36.4	30	0.3
Depreciation Study Differences						50.0
Total Distribution System	**20,631.8**	**8,048.6**	**0.0**	**28,680.4**		**569.5**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	2,615.2	4,246.7		6,861.8	50	49.9
Building and Improvements	10,587.8	135.0		10,722.8	55	192.5
Office Furniture and Equipment	1,919.3	40.0		1,959.3	20	43.1
Communication Site Towers	19.3	0.0		19.3	40	0.3
Communication Site Fences	88.4	63.7		152.2	30	1.9
Computer Hardware	1,437.6	193.0		1,630.6	7	142.4
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	2,848.0	366.5		3,214.5	20	111.9
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,623.4	139.0		5,762.4	20	222.0
Company Owned Houses / Land	59.0	0.0		59.0	40	1.1
Company Owned Houses	2,152.4	810.2		2,962.6	40	19.2
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**27,354.8**	**5,994.1**	**0.0**	**33,348.8**		**717.1**
Transportation						
Utility Vehicles	357.6	35.0		392.6	8	14.0
Sedans and Stationwagons	211.7	0.0		211.7	11	14.8
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.5
Trucks 3/4 to 2 Ton	3,289.7	623.8		3,913.5	9	302.9
Trucks > 3 Ton	1,459.8	389.5		1,849.3	20	58.4
Foremost	1,003.9	0.0		1,003.9	20	60.7
Depreciation Study Differences						19.3
Total Transportation	**6,448.2**	**1,048.3**	**0.0**	**7,496.4**		**475.6**
Critical Spares						
Critical Spares	1,165.7	0.0		1,165.7	0	0.0
Total Critical Spares	**1,165.7**	**0.0**	**0.0**	**1,165.7**		**0.0**
LNG Production						
Structures and Improvements	6,184.7	0.0		6,184.7	72	85.9
Fuel Holders	13,200.7	0.0		13,200.7	60	200.4
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	548.4	800.0		1,348.4	2	0.0
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,870.0	20.2		2,890.2	30	95.7
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**48,130.4**	**820.2**	**0.0**	**48,950.6**		**997.5**
Right of Use Assets						
Right of Use Assets	1,180.9	750.1		1,931.0		113.1
Total Right of Use Assets	**1,180.9**	**750.1**	**0.0**	**1,931.0**		**113.1**
Total	**702,516.9**	**31,557.2**	**2,539.6**	**731,534.4**		**14,301.4**

Yukon Energy Corporation Schedule 3A - 2024

Calculation of Depreciation Expense for 2024 YUB-YEC-1-26 Attachment 1

$000

Description	Cost at 2023 Year End	2024 Additions	2024 Disposals/ Adjustments	Cost at 2024 Year End	Proposed Depreciation Rate (Years)	Forecast 2024
Land						
Hydraulic Production	444.9	0.0		444.9	0	0.0
Diesel Production	27.7	0.0		27.7	0	0.0
Main Transmission Facilities	576.9	0.0		576.9	0	0.0
Distribution System	17.8	0.0		17.8	0	0.0
General Plant	548.0	0.0		548.0	0	0.0
Rights	127.2	0.0	1.6	125.6	50	1.6
Depreciation Study Differences						0.0
Total Land	**1,742.4**	**0.0**	**1.6**	**1,740.9**		**1.6**
Hydro Plant						
Structures and Improvements	54,813.8	1,000.0		55,813.8	72	758.6
Buildings and Improvements	10,278.7	0.0		10,278.7	40	257.0
Reservoirs, Dams, and Waterways	167,912.3	0.0		167,912.3	103	1,849.7
Hydro, Dams wtwys Twin Assets	6,711.4	0.0		6,711.4		0.0
Overhaul	11,514.0	0.0		11,514.0	10	1,151.4
Waterwheels,Turbines & Generation	28,222.8	0.0		28,222.8	85	325.4
Accessory Electric Equipment	27,366.3	0.0		27,366.3	40	727.1
Accessory Digital Equipment	851.2	0.0		851.2	20	42.6
Misc Power Plant Equipment	13,162.2	225.0		13,387.2	30	438.7
Fencing	107.1	0.0		107.1	30	2.7
Depreciation Study Differences						-140.3
Total Hydro Plant	**320,939.8**	**1,225.0**	**0.0**	**322,164.8**		**5,412.9**
Diesel Production						
Structures and Improvements	1,562.4	0.0		1,562.4	72	21.7
Buildings and Improvements	474.7	0.0		474.7	55	8.6
Fuel Holders, Products, and ACC	2,735.6	0.0		2,735.6	40	45.1
Generating Equipment and Prime	16,506.2	18,175.5		34,681.6	40	390.5
Overhaul	2,962.8	450.0		3,412.8	5	0.0
Minto Generating Equipment	243.5	0.0		243.5	12	0.0
Accessory Electric Equipment	8,938.0	0.0		8,938.0	45	208.8
Misc Power Plant Equipment	1,874.4	50.0		1,924.4	30	60.4
Depreciation Study Differences						-74.4
Total Diesel Production	**35,297.6**	**18,675.5**	**0.0**	**53,973.0**		**660.8**
Wind Turbine						
Wind Turbine	0.0	0.0		0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**	**0.0**		**0.0**
Main Transmission Facilities						
Poles and Fixtures	84,788.8	16,448.9		101,237.6	65	1,304.3
Brushing	16,756.3	0.0		16,756.3	60	263.8
Survey Costs	4,297.2	0.0		4,297.2	60	68.0
Overhead Conductors / Poles	20,202.9	0.0		20,202.9	60	314.0
Overhead Conductors / Towers	278.0	0.0		278.0	60	4.2
Substation Equipment	65,107.5	1,184.0		66,291.5	54	1,315.9
Substation VGC Group - Gold Mine	10,688.6	0.0		10,688.6	10	890.7
STATCOM - VGC Group - Gold Mine	13,991.5	0.0		13,991.5	10	1,399.1
Other - VGC Group - Gold Mine	848.0	0.0		848.0	10	84.8
Substation Buildings	8,907.6	0.0		8,907.6	55	28.1
Substation Fences	274.5	0.0		274.5	30	7.1
Depreciation Study Differences						-79.6
Total Main Transmission Facilities	**226,140.8**	**17,632.9**	**0.0**	**243,773.6**		**5,600.5**
Sub Transmission Lines						
Poles and Fixtures	4,584.0	0.0		4,584.0	65	68.5
25Kv Minto Spur- Structure	2,646.1	0.0		2,646.1	12	13.3
Brushing	41.6	0.0		41.6	60	0.7
Brushing Minto	432.5	0.0		432.5	12	2.2
Survey costs	0.0	0.0		0.0	60	0.0
Survey costs Minto	95.1	0.0		95.1	12	0.5
Overhead Conductors	1,837.9	0.0		1,837.9	60	24.4
Underground Conductors / Conduit	78.8	0.0		78.8	45	1.8
Overhead Conductors Minto	920.7	0.0		920.7	12	4.6
Substation Equipment	8,092.8	50.0		8,142.8	54	149.9
Substation Equipment Minto	7,111.2	0.0		7,111.2	12	38.8
Depreciation Study Differences						-46.0
Total Sub Transmission Lines	**25,840.9**	**50.0**	**0.0**	**25,890.9**		**258.6**
Distribution System						
Poles and Fixtures	17,787.1	700.0		18,487.1	40	433.1
Brushing	44.8	0.0		44.8	50	0.9
Survey costs	662.9	0.0		662.9	50	18.9
Overhead conductors - Poles	285.8	1,926.8		2,212.6	50	5.4
Overhead Costs	2,119.5	0.0		2,119.5	40	53.0

Yukon Energy Corporation Schedule 3A - 2024

Calculation of Depreciation Expense for 2024 YUB-YEC-1-26 Attachment 1

$000

Description	Cost at 2023 Year End	2024 Additions	2024 Disposals/ Adjustments	Cost at 2024 Year End	Proposed Depreciation Rate (Years)	Forecast 2024
Underground Services	385.2	0.0		385.2	40	9.6
Underground Conduit	43.4	0.0		43.4	40	1.1
Wind Monitoring Equipment	0.0	0.0		0.0	0	0.0
Meters	312.6	0.0		312.6	16	5.6
Meter Equipment	288.4	0.0		288.4	16	7.0
Substation Equipment	1,903.4	0.0		1,903.4	40	45.7
Substation Buildings	64.8	0.0		64.8	55	1.2
Substation Fences	100.3	0.0		100.3	30	3.0
Street Lights	603.4	0.0		603.4	40	14.1
Line Transformers	4,042.5	0.0		4,042.5	35	111.5
Sentinel Lights	36.4	0.0		36.4	30	0.3
Depreciation Study Differences						50.0
Total Distribution System	**28,680.4**	**2,626.8**	**0.0**	**31,307.2**		**760.3**
Building and Other Equipment						
Survey Costs Land	4.3	0.0		4.3	50	0.1
Structures and Improvements (Hydro)	6,861.8	1,200.0		8,061.8	50	134.9
Building and Improvements	10,722.8	90.0		10,812.8	55	195.0
Office Furniture and Equipment	1,959.3	25.0		1,984.3	20	43.3
Communication Site Towers	19.3	0.0		19.3	40	0.3
Communication Site Fences	152.2	25.0		177.2	30	4.0
Computer Hardware	1,630.6	730.0		2,360.6	7	153.4
Computer Software	0.0	0.0		0.0	5	0.0
Tool and Instruments	3,214.5	880.0		4,094.5	20	128.6
Wind Monitoring Equipment	0.0	0.0		0.0	15	0.0
Communication Equipment	5,762.4	260.0		6,022.4	20	223.2
Company Owned Houses / Land	59.0	0.0		59.0	40	1.1
Company Owned Houses	2,962.6	0.0		2,962.6	40	39.5
Depreciation Study Differences						-67.3
Total Building and Other Equipment	**33,348.8**	**3,210.0**	**0.0**	**36,558.8**		**856.2**
Transportation						
Utility Vehicles	392.6	35.0		427.6	8	16.9
Sedans and Stationwagons	211.7	0.0		211.7	11	14.8
Trucks & Pole Trailer	71.8	0.0		71.8	25	2.9
Pole Trailers > 10,000 Lbs	53.7	0.0		53.7	25	2.6
Trucks 3/4 to 2 Ton	3,913.5	567.0		4,480.5	9	336.8
Trucks > 3 Ton	1,849.3	0.0		1,849.3	20	77.9
Foremost	1,003.9	0.0		1,003.9	20	60.9
Depreciation Study Differences						19.3
Total Transportation	**7,496.4**	**602.0**	**0.0**	**8,098.4**		**532.0**
Critical Spares						
Critical Spares	1,165.7	0.0		1,165.7	0	0.0
Total Critical Spares	**1,165.7**	**0.0**	**0.0**	**1,165.7**		**0.0**
LNG Production						
Structures and Improvements	6,184.7	0.0		6,184.7	72	85.9
Fuel Holders	13,200.7	0.0		13,200.7	60	201.0
Generator	20,891.0	0.0		20,891.0	40	522.3
Overhaul	1,348.4	400.0		1,748.4	2	400.0
Accessory Electric Equipment	3,655.9	0.0		3,655.9	45	81.2
Misc Power Plant Equipment	2,890.2	800.0		3,690.2	30	96.3
Fence	779.7	0.0		779.7	30	26.0
Depreciation Study Differences						-14.0
Total LNG Prodution	**48,950.6**	**1,200.0**	**0.0**	**50,150.6**		**1,398.7**
Right of Use Assets						
Right of Use Assets	1,931.0			1,931.0		225.6
Total Right of Use Assets	**1,931.0**	**0.0**	**0.0**	**1,931.0**		**225.6**
Total	**731,534.4**	**45,222.1**	**1.6**	**776,755.0**		**15,707.1**

YUKON ENERGY CORPORATION Schedule 3B - 2023

Calculation of Amortization Expense for Deferred Costs and Intangibles (2023) YUB-YEC-1-26 Attachment 1

$000

	Total Expenditures					
	Dec 31	2023 Forecast		Dec 31	Amortization Rate and Method	2023 Forecast
	2022	Additions	Transfers /Retired	2023		Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Disaster Recovery Plan	4			4	SL-5 years	0
N-1 Event Risk Assessment	129			129	SL-5 years	26
Dyke Heating Pipe Assessment	68			68	SL-5 years	14
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	3
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	3
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	326	70		396	SL-5 years	65
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
WTE Contributions	(283)			(283)	SL-5 years	(7)
Southern Lakes Enhanced Storage		8,784		8,784	SL-10 years	-
Public Safety Plans		225		225	SL-5 years	-
System Wide Stability Study		200		200	SL-5 years	-
System Wide Arc Flash Study		198		198	SL-5 years	-
Mayo Civil Infrastructure Refurbishment Planning		168		168	SL-5 years	-
Digital Strategy and Policy Development		120		120	SL-5 years	-
Privacy Management Program		100		100	SL-5 years	-
Vegetation Management Plan Update		225		225	SL-5 years	-
Other Projects with <$100k Spending		319		319	SL-5 years	-
Total Feasibility Study Closed	7,263	10,410	-	17,673		1,049
Regulatory						
Completed Projects:						
DSM	3,378	1,272		4,649	SL-10 years	338
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
Asset Appraisal-Replace Cost	47			47	SL-5 years	3
Victoria Gold PPA	142			142	SL-5 years	17
LED Streetlight 2015/2018	261			261	SL-5 years	52
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,080)	(22)		(2,102)	SL-10 years	(208)
Victoria Gold PPA Contributions	(100)			(100)	SL-5 years	(12)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)		386		386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)		23		23	Hearing Reserve	
Total Regulatory Closed	2,465	1,659	-	4,124		321
Relicensing						
Completed Projects:						
Aishihik 2020 3 Year Relicensing	112			112	License term	6
Aishihik 2022 5 Year Relicensing	3,903	575		4,479	License term	781
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	21
Mayo Relicensing	129			129	License term	11
Total Relicensing Closed	4,470	575	-	5,046		820
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**14,453**	**12,644**	**0**	**27,097**		**2,241**
Intangibles						
Completed Projects:						
Software Costs	1,185	441		1,627	SL-5 years	226
Financial Software Costs	7,386			7,386	SL-10 years	492
PAMMS Asset Management Framework		5,466		5,466	SL-10 years	
Total Intangibles Closed	8,572	5,907	-	14,479		718
Total Deferred and Intangibles Closed	**23,025**	**18,551**	**0**	**41,576**		**2,959**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION Schedule 3B - 2024

Calculation of Amortization Expense for Deferred Costs and Intangibles (2024) YUB-YEC-1-26 Attachment 1

$000

	Total Expenditures					
	Dec 31	2024 Forecast		Dec 31	Amortization Rate and Method	2024 Forecast
	2023	Additions	Transfers /Retired	2024		Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Dyke Heating Pipe Assessment	68			68	SL-5 years	10
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	1
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	1
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	396			396	SL-5 years	79
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
Southern Lakes Enhanced Storage	8,784			8,784	SL-10 years	878
Public Safety Plans	225			225	SL-5 years	45
System Wide Stability Study	200			200	SL-5 years	40
System Wide Arc Flash Study	198			198	SL-5 years	40
Mayo Civil Infrastructure Refurbishment Planning	168			168	SL-5 years	34
Digital Strategy and Policy Development	120			120	SL-5 years	24
Privacy Management Program	100			100	SL-5 years	20
Vegetation Management Plan Update	225			225	SL-5 years	45
Cyber Security Framework		140		140	SL-5 years	
Transmission Line Detailed Inspection Program		250		250	SL-5 years	
Gates/TIV's Certification Assessment System Wide		200		200	SL-5 years	40
Digital Reporting Review		125		125	SL-5 years	
Records Policy Planning and Program Development		100		100	SL-5 years	
Breaker Condition Assessment		100		100	SL-5 years	
Other Projects with <$100k Spending	319	(10)		309	SL-5 years	64
Total Feasibility Study Closed	17,823	905	-	18,728		2,268
Regulatory						
Completed Projects:						
DSM	4,649	1,160		5,809	SL-10 years	465
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,102)			(2,102)	SL-10 years	(210)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	386			386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)	23			23	Hearing Reserve	
GRA 2023-2024 (Hearing Reserve Acct)		-		-	Hearing Reserve	
Total Regulatory Closed	3,775	1,160	-	4,935		386
Relicensing						
Completed Projects:						
Aishihik 2022 5 Year Relicensing	4,479			4,479	License term	896
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	20
Mayo Relicensing	129			129	License term	11
WRGS Thermal Assessment & Permitting		413		413	License term	
Total Relicensing Closed	4,933	413	-	5,346		928
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**26,786**	**2,478**	**0**	**29,264**		**3,632**
Intangibles						
Completed Projects:						
Software Costs	1,627	380		2,007	SL-5 years	279
Financial Software Costs	7,386			7,386	SL-10 years	455
PAMMS Asset Management Framework	5,466			5,466	SL-10 years	547
Total Intangibles Closed	14,479	380	-	14,859		1,281
Total Deferred and Intangibles Closed	**41,265**	**2,858**	**0**	**44,123**		**4,913**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
	2021 GRA Compliance				**Deemed Ratio**			
1	Long-Term debt	S.11 L.19	185,526	60.0%	60.0%	185,679	2.94%	5,453
2	Common Stock		123,705	40.0%	40.0%	123,786	8.65%	10,708
3	Total	S.5 L.3	309,231	100.0%	100.0%	309,466	5.22%	16,161
	2021 Actual							
7	Long-Term debt	S.11 L.19	175,620	57.8%		173,892	2.93%	5,102
8	Common Stock		128,322	42.2%		127,060	8.93%	11,346
9	Total	S.5 L.3	303,942	100.0%		300,951	5.47%	16,448
	2022 Actual							
10	Long-Term debt	S.11 L.19	181,949	56.0%		169,841	2.88%	4,896
11	Common Stock		143,174	44.0%		133,646	10.17%	13,607
12	Total	S.5 L.3	325,123	100.0%		303,487	3.17%	18,503
	Forecast 2023				**Deemed Ratio**			
13	Long-Term debt	S.11 L.19	197,376	57.9%	60.0%	195,205	3.28%	6,395
14	Common Stock		143,372	42.1%	40.0%	130,136	8.70%	11,322
15	Total	S.5 L.3	340,749	100.0%	100.0%	325,341	5.45%	17,717
	Forecast 2024				**Deemed Ratio**			
19	Long-Term debt	S.11 L.19	216,478	60.0%	60.0%	216,572	3.39%	7,343
20	Common Stock		144,062	40.0%	40.0%	144,381	8.70%	12,561
21	Total	S.5 L.3	360,540	100.0%	100.0%	360,953	5.51%	19,904

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Net rate base	S.1 L.23	309,466	300,951	303,487	325,341	360,953
2	Average Rate of return on rate base		5.22%	5.47%	6.10%	5.45%	5.51%
3	Utility income	S.8 L.1	16,161	16,448	18,503	17,717	19,904
4	Utility expenses						
5	Operating and maintenance (note 1)	S.6 L.3	43,211	40,096	44,641	50,017	53,178
6	Taxes other than income	S.6 L.4	750	739	743	758	777
7	Amortization of deferred costs	S.6 L.5	4,063	5,529	3,886	3,657	5,594
8	Reserve for Injuries and Damages	S.6 L.6	616	616	616	616	616
9	Depreciation	S.6 L.7	13,436	14,927	13,310	14,301	15,707
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,684)	(6,347)	(5,384)	(5,918)	(6,096)
11	Disallowed depreciation		(238)	(416)	(718)	(44)	(44)
12	Donations		(120)	(117)	(121)	(120)	(120)
13	Total utility expenses		57,033	55,026	56,972	63,268	69,611
14	Revenue Requirement	S.6 L.1	73,193	71,473	75,475	80,985	89,515

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Revenues (note 1)	S.5 L.14	73,193	71,473	75,475	80,985	89,515
2	**Operating expenses**						
3	Operating and maintenance	S.10 L.15	43,211	40,096	44,641	50,017	53,178
4	Taxes other than income	S.5 L.6	750	739	743	758	777
5	Amortize deferred costs		4,063	5,529	3,886	3,657	5,594
6	Reserve for Injuries and Damages	S.5 L.8	616	616	616	616	616
7	Depreciation		13,436	14,927	13,310	14,301	15,707
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,684)	(6,347)	(5,384)	(5,918)	(6,096)
9	Total		57,391	55,559	57,811	63,432	69,775
10	**Operating income**		15,802	15,914	17,664	17,553	19,740
11	**Other income**						
12	Allowed for Funds Used	S.8 L.2	1,188	942	1,060	2,215	3,723
13	Miscellaneous (note 2)	S.8 L.3	(131)	(812)	(888)	(1,310)	(3,562)
14	Total		1,057	130	172	906	161
15	**Other expenses**						
16	Interest expense	S.8 L.4	5,655	2,768	(1,822)	8,644	10,034
17	Total		5,655	2,768	(1,822)	8,644	10,034
18	**Net earnings**	S.8 L.8	11,205	13,276	19,658	9,814	9,867

Note 1: Includes revenues from sales and other revenues.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Balance at beginning of year		68,883	64,263	82,445	93,966	82,841
	Add:						
2	Net earnings	S.6 L.18	11,205	13,276	19,658	9,814	9,867
3	IFRS Comprehensive Income Adjustment			4,906	3,364	-	-
4	Balance at end of year before dividend		80,088	82,445	105,466	103,781	92,708
	Less:						
5	Common Dividends (note 1)		13,592	-	11,500	20,940	-
6	Balance at end of year		66,495	82,445	93,966	82,841	92,708
	Shareholder's Equity						
7	Common shares		56,294	54,968	54,968	54,968	57,606
8	Retained earnings		66,495	82,445	93,966	82,841	92,708
9	Total		122,789	137,413	148,935	137,810	150,314

Note:
1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation

Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	Utility Income (Return on Rate Base)	S.5 L.3	16,161	16,448	18,503	17,717	19,904
	Add:						
2	Allowance for funds used	S.6 L.12	1,188	942	1,060	2,215	3,723
3	Other income (expenses)	S.6 L.13	(131)	(812)	(888)	(1,310)	(3,562)
			17,218	16,578	18,675	18,623	20,065
	Less:						
4	Interest - long-term	S.6 L.17	5,655	2,768	(1,822)	8,644	10,034
5	Donations	S.5 L.12	120	117	121	120	120
6	Disallowed costs		-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	238	416	718	44	44
			6,013	3,302	(983)	8,809	10,198
8	Net earnings	S.6 L.18	11,205	13,276	19,658	9,814	9,867

Yukon Energy Corporation
Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
YUB-YEC-1-26 Attachment 1

Line No.	Description	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Residential**					
2	Customers	1,780	1,813	1,822	1,858	1,898
3	Sales in MWh	16,210	17,421	17,334	17,693	18,090
4	MWh sales per customer	9.1	9.6	9.5	9.5	9.5
5	Revenue ($000s)	2,384	2,513	2,472	2,532	2,611
6	Cents per KWh	14.7	14.4	14.3	14.3	14.4
7	**General Service**					
8	Customers	514	528	519	529	536
9	Sales in MWh	32,323	29,584	30,662	38,569	44,698
10	MWh sales per customer	62.9	56.0	59.1	72.9	83.4
11	Revenue ($000s)	5,388	4,911	5,005	6,272	7,175
12	Cents per KWh	16.7	16.6	16.3	16.3	16.1
13	**Industrial**					
14	Sales in MWh	102,904	91,143	95,169	75,045	69,368
15	Revenue ($000s)	11,481	11,129	12,206	9,718	8,771
16	Cents per KWh	11.2	12.2	12.8	12.9	12.6
17	**Street lights**					
18	Sales in MWh	168	168	168	168	168
19	Revenue ($000s)	82	82	82	82	82
20	Cents per KWh	48.8	48.8	48.9	48.9	48.9
21	**Space lights**					
22	Sales in MWh	10	9	9	9	9
23	Revenue ($000s)	3	2	2	2	2
24	Cents per KWh	26.6	27.2	27.3	27.3	27.3
25	**Total Company - Firm Retail and Industrial**					
26	Customers	2,293	2,341	2,341	2,387	2,434
27	Sales in MWh	151,614	138,325	143,341	131,484	132,333
28	Revenue ($000s)	19,337	18,638	19,767	18,606	18,642
29	Cents per KWh	12.8	13.5	13.8	14.2	14.1
30	**Wholesale sales**					
31	Sales in MWh	343,537	348,983	346,339	351,291	355,857
32	Revenue ($000s)	28,507	28,959	29,170	29,150	29,529
33	Cents per KWh	8.3	8.3	8.4	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	495,151	487,308	489,680	482,775	488,190
36	Revenue ($000s)	47,844	47,597	48,937	47,756	48,171
37	Cents per KWh	9.7	9.8	10.0	9.9	9.9
38	**Secondary**					
39	Sales in MWh	0	4,739	3,448	2,931	2,931
40	Revenue ($000s)	0	330	365	358	358
41	Cents per KWh	0.0	7.0	10.6	12.2	12.2
42	**Total Company**					
43	Sales in MWh	495,151	492,047	493,128	485,706	491,121
44	Revenue ($000s)	47,844	47,927	49,302	48,114	48,528
45	Cents per KWh	9.7	9.7	10.0	9.9	9.9
46	Rider J	15,887	19,430	26,348	26,265	26,183
47	GRA Increase Req'd	9,149			6,212	14,410
48	Total Sales of Power	72,880	67,357	75,650	80,591	89,121
49	Other Revenues	369	-1,471	382	394	394
50	Total Revenues	73,249	65,886	76,032	80,985	89,515

Yukon Energy Corporation

Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Utility operations**						
2	Production		10,438	10,360	11,320	13,490	15,525
3	Transmission and distribution		3,188	3,133	2,972	3,273	3,295
4	General		1,763	1,628	1,699	1,780	1,697
5	Administration and general		10,397	10,641	11,603	12,893	13,157
6	Insurance		1,423	1,550	1,875	2,190	2,417
7	Sub-total		27,209	27,312	29,469	33,625	36,091
8	Donations		120	117	121	120	120
9	Sub-total		120	117	121	120	120
10	O&M not including fuel and						
11	purchased power		27,329	27,429	29,590	33,745	36,211
12	Fuel		15,829	12,618	14,725	15,122	13,831
13	Purchased power		53	49	326	1,150	3,136
14	Sub-total		15,882	12,667	15,051	16,272	16,967
15	Total operating and maintenance	S.6 L.3	43,211	40,096	44,641	50,017	53,178
	O&M Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:						
16	*Reserve for Injuries and Damages*		*616*	*616*	*616*	*616*	*616*
17	*Property Taxes*		*750*	*739*	*743*	*758*	*777*
18	*less: Donations*		*-120*	*-117*	*-121*	*-120*	*-120*
19	*O&M per Table 3.3 (Tab 3)*		*28,575*	*28,667*	*30,828*	*34,999*	*37,484*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
1	**Total FTEs**	Tab 3, Table 3.4	100.6	101.9	107.0	114.0	119.8
2	**Total Labour Costs**		15,719	15,807	15,753	18,489	19,695
3	O&M Labour Costs	Sum Lines 5-9	13,016	13,167	13,675	15,183	16,079
4	Labour Costs to Capital		2,703	2,640	2,077	3,305	3,616
	Labour Costs						
5	Production		4,802	5,076	5,051	5,693	6,034
6	Transmission		674	645	548	657	666
7	Distribution		629	701	687	752	764
8	General		372	275	291	343	350
9	Administration		6,539	6,471	7,098	7,739	8,265
10	Total Labour		13,016	13,167	13,675	15,183	16,079

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
YUB-YEC-1-26 Attachment 1

Line No.	Description	Cross Ref.	2021 GRA Compliance	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
	Long-Term Debt Balance						
1	YDC Mayo B Flexible Term Debt		18,531	18,531	18,194	17,857	17,520
2	TD Bank Swap		7,858	7,831	7,413	6,987	6,552
3	YDC $92.5M Debt		66,672	66,672	62,988	59,304	55,620
4	YDC $5.5M Debt		5,505	5,505	5,505	5,505	5,505
5	YDC $21.0M Debt		15,948	15,948	15,109	14,269	13,430
6	YDC $12.1M Debt		12,136	12,136	12,136	12,136	12,136
7	TD Bank Swap		21,554	21,527	20,843	20,135	19,403
8	TD Bank Swap		6,303	6,295	6,089	5,877	5,659
9	YDC $2.9M Debt		2,871	2,871	2,871	2,871	2,871
10	2020 New Debt		12,715	4,640	4,488	4,333	4,175
11	YDC Debt - 2020		8,760	3,959	3,959	3,959	3,959
12	$7.7M TD Swap - 2021		0	7,518	7,301	7,079	6,850
13	$17.9M TD Swap - 2022		1,648	0	17,914	17,598	17,269
14	2023 New Debt			0	0	26,213	26,213
15	2024 New Debt			0	0	0	25,608
16	Minto Decommissioning Reserve		2,816	2,812	2,843	2,976	3,087
17	Current year-end balance		183,317	176,245	187,653	207,099	225,856
18	Previous year-end balance		187,736	174,995	176,245	187,653	207,099
19	Mid Year		185,526	175,620	181,949	197,376	216,478
	Interest Expenses						
20	YDC Mayo B Flexible Term Debt		1,030	1,030	1,012	993	975
21	TD Bank Swap		217	166	158	149	140
22	YDC $92.5M Debt		1,886	1,886	1,787	1,688	1,589
23	YDC $5.5M Debt		132	132	132	132	132
24	YDC $21.0M Debt		371	371	352	334	315
25	YDC $12.1M Debt		255	255	255	358	359
26	TD Bank Swap		803	744	721	697	673
27	TD Bank Swap		186	169	164	158	153
28	YDC $2.9M Debt		83	83	83	83	83
29	2020 New Debt		278	97	94	91	88
30	YDC Debt - 2020		192	62	62	62	62
31	$7.7M TD Swap - 2021		0	146	214	208	201
32	$17.9M TD Swap - 2022			0	183	724	711
33	2023 New Debt			0	0	650	1,109
34	2024 New Debt			0	0	0	635
35	Minto Decommissioning Reserve		16	13	31	133	110
36	Capital Lease Interest			0	2	6	5
37	**Total Cost of Interest**		5,449	5,153	5,249	6,467	7,340
38	Mid-Year Cost of Debt		2.94%	2.93%	2.89%	3.28%	3.39%

REFERENCE: **Application, PDF page 76; Appendix A to Board Order 2022-03, par. 368, PDF page 83**

ISSUE: LWRF

QUOTE: Application, PDF page 76:
The LWRF exists solely to minimize the effect on ratepayers "that would otherwise be caused by variation in actual renewal source availability, including the variation caused by drought conditions" (OIC 2021/16 as referenced by Board Order 2022-03, Appendix A, para 365), and was not established to provide any role in financing, or providing offsetting contributions, to YEC's rate base. In this regard, the LWRF deferral account is similar to the Deferral Fuel Price Variance Account (DFPVA), and it is not appropriate for either of these deferral accounts to have any impact on YEC rate base determination.

Appendix A to Board Order 2022-03, PDF page 83, par. 368:
The testimony of YEC in this proceeding stated that YEC expects the LWRF to maintain a positive balance (i.e., collecting funds for future low water events) and that a positive balance is expected to exist in most years.

QUESTION:

a) Does treating the LWRF as an offset to rate base risk the calculated value of the balance of the LWRF?

b) Is the calculated balance in the LWRF always available to cover fluctuations in renewal source availability, subject to the minimum and maximum balances of the LWRF?

c) Are the minimum and maximum balances in the LWRF based on requests by YEC to the Board?

d) Please explain why an amount that YEC collects from customers which is expected to maintain a positive balance in most years and is for a future event should not be treated as an offset to rate base.

e) Why is the DFPVA relevant to LWRF calculations?

ANSWER:

(a)

Treating the LWRF as an offset to rate base has no impact on the calculated balance of the LWRF, except for small changes that would occur due to interest on balance which was in place prior to the YUB Order 2022-03, as the LWRF is determined without any reference to rate base.

However, treating the LWRF as an offset to rate base results in the rate base being subject to the risk of changes in water availability, YUB decisions on the LWRF cap, and any other factors that result in a change to the LWRF - and those changes to rate base will concurrently impact YEC and (when YUB GRA decisions occur) ratepayers.

Treating the LWRF as an offset to rate base is also contrary to the requirements of section 32 of the *Public Utilities Act*. In particular, the balance of the LWRF is irrelevant to the Board's determination of what costs must be included in YEC's rate base in accordance with the statutory requirements set out in section 32(1) and (3), and there is nothing else in section 32 of the Act that could authorize the Board to apply the LWRF balance as an offset to rate base. As such, the effect of an offset would be to deny YEC the fair return (less 0.5%) that it is entitled to earn under section 2 of OIC 1995/90 on a rate base that is properly determined in accordance with section 32 of the Act.

(b)

The LWRF balance is available to stabilize rates, as intended in OIC 2021/16, by covering fluctuations in renewal source availability, subject to minimum and maximum balance of the LWRF. However, requiring the LWRF to be an offset to rate base results in LWRF balance changes in response to fluctuations in resource availability introducing potential rate instabilities linked to fluctuations in resource availability (contrary to OIC 2021/16 objectives). By way of example, a drought that shifts the LWRF balance from plus $16

million (current cap) to negative $16 million (current minimum) will increase rate base by $32 million absent any change in actual capital asset net rate base values and thereby increase revenue requirement related to return on rate base (equal to an annual return increase of $1.77 million based on 2024 GRA average cost of capital at 5.54%).

(c)

The Board determines minimum and maximum balances in the LWRF, typically based on requests by YEC to the Board.

The Board retains authority to reject YEC requests and/or to approve changes not related to any YEC requests.

(d)

The following summarize reasons why the LWRF use to fund rate base is not appropriate or consistent with normal principles established in Canada for utilities as directed by section 3 of OIC 1995/90:

- The LWRF exists today, as required by OIC 2021/16, to minimize the effect on ratepayers "that would otherwise be caused by variation in actual renewal source availability, including the variation caused by drought conditions." The LWRF today is not established to assist YEC in any way to fund, or to provide offsetting contributions, to YEC's rate base – and LWRF use as an offset to YEC rate base introduces new effects on ratepayers due to variations in actual renewable source availability, including the variation caused by drought conditions, that are clearly contrary to OIC 2021/16 objectives regarding the LWRF.

- Prior to OIC 2021/16, each YUB ruling on YEC GRA rate base from Order 1996-7 until Order 2022-03 did not in any way adjust YEC rate base to reflect the then balance in the LWRF, or in the equivalent DCF deferral account established in 1996 to meet objectives similar to OIC 2021/16 directives on the LWRF. Prior LWRF or DCF balances over this extensive earlier period showed material fluctuations on several occasions relating to water availability, mine load changes, changes in fund caps and other factors – and no Board decision at any time during this period suggested any basis to consider using the fund to offset rate base, let alone basing such a direction on an assumption that a positive balance might be

expected to exist in most years. The only change noted related to the LWRF in YEC's 2021 GRA was OIC 2021/16 – and this OIC only served to clarify by direction the LWRF objective to reduce effects on ratepayers otherwise caused by variations in renewal source availability. In summary, OIC 2021/16 provided no basis to introduce LWRF use as an offset to rate base – and this change involving LWRF fund use in effect contradicted, without any reasonable basis being provided, the specified objectives of OIC 2021/16.[1]

- Use of the LWRF to finance YEC rate base places new risks on YEC financing to the extent that LWRF funds are not YEC funds, and will vary due to factors beyond YEC's control, thereby placing YEC's overall long-term financing as required for its rate base at risk and without precedent to any comparator utility's business risks. YEC has no reasonable ability to forecast renewable source availability beyond about six to eighteen months, and in the case of drought risks could face material LWRF reductions within a period of a few years.

(e)

The DFPVA is relevant to LWRF only to the extent that both deferral accounts are established to address ratepayer cost risk responsibilities rather than funding of YEC rate base, and therefore it is not appropriate for either of these deferral accounts to have any impact or use on YEC rate base determination or funding.

[1] Appendix A to Board Order 2022-03 at par. 368 noted, as potential basis for this change, YEC testimony in the 2021 GRA proceeding "that YEC expects the LWRF to maintain a positive balance (i.e., collecting funds for future low water events) and that a positive balance is expected to exist in most years." No specific transcript reference was provided for this reference in Appendix A. Review of Volume 2 of the transcript indicates some discussion with Mr. Mollard at pages 182 to 190 where opinion was provided, based on models rather than historic actual experience, on a positive LWRF balance likely to be retained over many years – however, Mr. Mollard also made clear that the LWRF was not YEC money, that YEC viewed it as a trust fund for ratepayers, and that YEC did not consider it as an offset to rate base or as an amount to be capitalized. Review of DCF-LWRF year end balances from 2012 to 2021 shows six of 10 years when the actual balance was not stable at the then maximum allowed level.

REFERENCE: **Application, PDF page 76**

ISSUE: LWRF

QUOTE: The LWRF exists solely to minimize the effect on ratepayers "that would otherwise be caused by variation in actual renewal source availability, including the variation caused by drought conditions" (OIC 2021/16 as referenced by Board Order 2022-03, Appendix A, para 365), and was not established to provide any role in financing, or providing offsetting contributions, to YEC's rate base.

QUESTION:

a) Please provide any specific reference in OIC 2021/16 that directs the treatment of the LWRF balance.

b) Please confirm that, under the Board's direction from Board Order 2022-03, the balance in the LWRF remains available for the use for which it was originally intended.

ANSWER:

(a)

Section 3 of OIC 2021/16 adds section 9(6) to Rate Policy Directive (1995) that states as follows regarding the purpose of the Low Water Reserve Fund (LWRF) established to provide the required low water deferral account:

> "The Board must require Yukon Energy Corporation to operate a low water deferral account for the purpose of minimizing the effect on rates for retail customers and major industrial customers that would otherwise be caused by variation in actual renewable source availability, including the variation caused by drought conditions."

Section 3 of OIC 2021/16 also adds section 9(7) to (9) to Rate Policy Directive (1995) that provides further direction for the Board's treatment of the LWRF balance, including provisions:

- To credit the LWRF if actual renewable source availability is greater than long-term average annual renewable source availability (s. 9(7)(a));

- To charge the LWRF if actual renewable source availability is less than long-term average annual renewable source availability (s. 9(7)(b));

- For the Board to set the maximum balance and minimum balance for the LWRF "at amounts sufficient to achieve the purpose described in subsection (6)" (s. 9(8)); and

- For the Board to require that YEC apply to the Board for approval of an adjustment of rates for customers to enable a drawdown of the LWRF if the balance is greater than the allowed maximum (s. 9(9)(a)), or to enable a replenishment of the LWRF if the balance is less than the allowed minimum (s. 9(9)(b)).

OIC 2021/16 requires the LWRF to be used for the purpose described in subsection (6), as quoted above. This OIC has no provision enabling the LWRF balance to be used for any purpose that does not have the effect of "minimizing the effect on rates for retail customers and major industrial customers that would otherwise be caused by variation in actual renewable source availability, including the variation caused by drought conditions."

More specifically, OIC 2021/16 does not contemplate any use of the LWRF to finance YEC net rate base; nor does it contemplate use of the LWRF for any other similar purpose that could create an opportunity for increasing the effect of actual renewable source availability on rates (beyond the effects provided for in OIC 2021/16) for retail customers and major industrial customers. YEC submits that it is contrary to the direction in OIC 2021/16 to offset the LWRF from rate base. In particular, if the LWRF balance is offset from rate base, actual water conditions ***will have*** an impact on rates under drought conditions. That is the very impact that the LWRF was implemented to avoid.[1]

(b)

Not confirmed.

[1] See response to YUB-YEC-1-27(b) which provides an example where use of the LWRF to finance rate base during a drought would result in low water availability increasing rates by over $1.7 million.

Appendix A to Board Order 2022-03 (para. 368) directed YEC in its 2021 compliance filing "to treat the balance in the LWRF as an offset to rate base". Under this Board direction the balance in the LWRF is used for financing YEC net rate base as well as for the use directed in OIC 2021/16. This will create effects on rates that are inconsistent with the use for which the LWRF was originally intended under OIC 2021/16 to the extent that LWRF balance changes create new effects on rates caused by the variation in actual renewable source availability. By way of example, a drought that shifts the LWRF balance from plus $16 million (current cap) to negative $16 million (current minimum) will increase rate base by $32 million absent any change in actual capital asset net rate base values and thereby increase revenue requirement related to return on rate base (equal to an annual return increase of $1.77 million based on 2024 GRA average cost of capital at 5.54%).

Please also see response to YUB-YEC-1-26 which shows how using the LWRF as an offset to rate base during the 2023-24 GRA test years results in changes in revenue requirement that are linked to forecast renewable generation varying from the LTA forecasts directed by OIC 2021-16.

REFERENCE: **Application, PDF page 78**

ISSUE: Hearing cost reserve account

QUOTE: The Proposed 2024 column does not include 2023/24 GRA hearing related costs as the costs are included in the hearing reserve after approval by the YUB and YEC does not expect the 2023/24 GRA hearing costs will be approved by the end of 2024. YEC will update the account balance based on information available at the time of compliance filing.

QUESTION:

a) Hearing costs are not considered until 30 days after the issuance of a Board decision. Is YEC providing an estimate at the time of its compliance filing, or is YEC waiting for the Board determination regarding hearing costs?

b) Please confirm that all costs included in the annual costs row of Table 3.14.1, Hearing Cost Reserve Account Continuity Schedule, have been approved by the Board by way of a cost Board Order. If not confirmed, please explain.

ANSWER:

(a)

The annual costs in the hearing reserve are only updated for actual costs approved by the Board. YEC is waiting for Board determination of the 2023/24 GRA hearing costs; as YEC does not expect a decision on the 2023/24 GRA hearing costs until 2025, there is no amount expected to be available at the time of the compliance filing update for these specific costs. However, YEC is also waiting for cost awards relating to the YEC 2021 GRA R&V Application; YEC submitted its application for cost awards relating to this proceeding on February 8, 2023, and fully expects the Board to decide on this prior to completion of the 2023/24 GRA compliance filing. Therefore, YEC is expecting to update the account balance for the YEC 2021 GRA R&V Application costs in its compliance filing.

(b)

Confirmed.

REFERENCE: **Application, PDF page 80**

ISSUE: Proposed IPP purchase cost deferral account

QUOTE: As noted in Section 3.6.4, based on Order in Council (OIC) 2019/25 YEC has created a deferral account that defers the variances between approved power purchase costs in rates and actual purchase costs [capital related costs are recovered through depreciation expense and rate base].

On a long-term average basis, using the LTA thermal calculation table from the 2021 GRA, YEC estimated the IPP purchases of $0.313 million in 2022 resulted in a $0.286 million reduction of thermal costs [please see Section 3.6.4 for details].

QUESTION:

a) Please explain how the IPP purchase cost deferral account would operate with numerical examples.

b) Please explain the necessity of LTA thermal calculations with respect to IPP purchases.

ANSWER:

(a) and (b)

Section 2 of Order in Council (OIC) 2019/25, *Direction to the Yukon Utilities Board (Independent Power Production Regulation)*, requires the Board to allow the utility to recover the cost of purchasing electricity under an electricity purchase agreement, as well as third party consultant costs (including legal fees) incurred by the utility in relation to the development and implementation of the agreement, and the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

Accordingly, YEC has created a deferral account to comply with OIC 2019/25 requirements that defers the variances between approved power purchase costs in rates and actual purchase costs.

As reviewed in response to YUB-YEC-1-32(b), LTA thermal calculations are needed for the proposed IPP purchase cost deferral account to address YEC overall net cost effects related to variances in IPP purchase volumes from approved GRA forecasts.

The following table illustrates numerical examples of how the deferral account works under two scenarios.

- Actuals lower than approved:
  - The 2023 opening balance is $0.026 million [owing from customers].
  - Assumed variance IPP deliveries is -1.1 GWh or -$0.198 million [lower actuals compared to approved].
  - The LTA thermal displacement benefits at -0.649 GWh [based on -1.1 GWh times 59%] or -$0.131 million [-0.649 GWh times weighted average fuel cost of $0.2022/kWh].
  - The net transfer to the deferral account for 2023 is -$0.067 million
  - The 2023 closing balance is -$0.041 million [owing to customers].

- Actuals higher than approved:
  - The 2023 opening balance is $0.026 million [owing from customers].
  - Assumed variance IPP deliveries is 1.1 GWh or $0.198 million [higher actuals compared to approved].
  - The LTA thermal displacement benefits at 0.649 GWh [based on 1.1 GWh times 59%] or $0.131 million [0.649 GWh times weighted average fuel cost of $0.2022/kWh].
  - The net transfer to the deferral account for 2023 is $0.067 million.
  - The 2023 closing balance is $0.093 million [owing from customers].

		Actuals lower than approved			Actuals higher than approved		
		2023 GRA Approved IPP	2023 Actuals	Variance	2023 GRA Approved IPP	2023 Actuals	Variance
A	**2023 Opening Balance, $000**			**26**			**26**
B	IPP Purchases, MWh	6,102	5,002	-1,100	6,102	7,202	1,100
C	IPP Purchase Cost, $000	1,099	901	-198	1,099	1,297	198
D	LTA thermal as % of Incremental Load			59%			59%
E=B*D	Calculated IPP LTA Thermal benefits, MWh			-649			649
E1	Diesel			-65			65
E2	LNG			-584			584
F=E*Fuel Cost	Calculated IPP LTA Thermal benefits, $000			-131			131
G=C-F	Net Transfer to IPP Deferral Account, $000			-67			67
H=A+G	**2023 Closing Balance, $000**			**-41**			**93**

REFERENCE: **Application, PDF pages 81-82Tab 7, Schedule 11**

ISSUE: Cost of debt

PREAMBLE: Schedule 11 provides a listing of YEC's long-term debt instruments.

QUESTION:

a) Please explain why the debt instruments on lines 4, 6, 9, and 11 do not have declining balances. Do these debt instruments have annual principal payments? If not, please explain why not.

ANSWER:

(a)

These debt instruments do not have annual principal payments, as disclosed on page 9-35. YEC does not pay annual principal payments in accordance with their respective agreements; principal is due in full on maturity.

REFERENCE: **Application, PDF page 86**

ISSUE: IPP purchase cost deferral account

QUOTE: These OIC requirements apply each year, regardless of whether YEC has been able to address specific adjustments needed in rates through a GRA process. Accordingly, a deferral account mechanism is needed to deal with variances that arise between YEC's costs incurred and its ability to recover these costs through rates.

QUESTION:

a) Does OIC 2019/25 refer to costs only as those invoiced to YEC by the IPP — i.e., a price x volume relationship?

b) Please explain the necessity of LTA thermal calculations with respect to IPP purchases.

ANSWER:

(a)

No - Section 2(2) of OIC 2019/25 describes the following utility costs to be recovered for eligible electricity purchase agreements, which include costs beyond those invoiced to YEC by the IPP:

1. The cost of purchasing electricity under an electricity purchase agreement;
2. Third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement; and
3. The cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

Section 5 of OIC 2019/25 also provides for reasonable compensation to be paid by the utility to the owner of the independent power production facility in the event that the facility is unable to deliver electricity to the utility as a result of damage to, or a failure of, infrastructure or equipment for which the utility is responsible.

The IPP program is relatively new and the utilities are presented with increased risk associated with operating the grid with new intermittent and not dispatchable supply options. In particular, IPPs can contribute to system disturbances which in turn could lead to additional outages. Currently, YEC is planning to curtail the IPP deliveries when it is deemed to have an impact on grid stability. In those cases, YEC still has to pay the IPPs based on agreements which would fall under section 5 of OIC 2019/25. These costs will be reflected as part of power purchase costs in the deferral account.

(b)

LTA thermal calculations are only referenced for the purpose of the proposed IPP purchase cost deferral account. As reviewed below, LTA thermal calculations are needed for the proposed IPP purchase cost deferral account to address YEC overall net cost effects related to variances in IPP purchase volumes from approved GRA forecasts.

The stated purpose of the proposed deferral account for YEC is to defer the variances between YEC's approved power purchase costs in rates (as approved for the last GRA) and YEC's actual costs related to IPP purchases. As reviewed below, IPP LTA thermal displacement benefits related to the IPP purchase volume variances is proposed to be included in the deferral account as an offset to the power purchase cost variance:

- Absent consideration of LTA thermal displacement benefits, the deferral account would address variances in YEC's costs for IPP purchases simply by reference to variance in IPP volumes and the applicable IPP pricing. For example, in Table 3.16 in the Application, the $913,000 variance (increase) in IPP purchase costs related to the 1,950 MWh assumed variance (increase) in IPP purchases (presumably due to an added IPP not considered in the last GRA approved IPP volumes and costs).

- Compensating YEC for this increased IPP purchase cost of $913,000 in the above example, however, would fail to recognize that a GRA revenue requirement assessment of net YEC costs related to IPP renewable energy deliveries would take into consideration YEC thermal fuel cost savings resulting from displacement of thermal energy generation requirements. These thermal fuel cost savings in a GRA assessment would be determined based on LTA thermal displacement benefits. In the Table 3.16 example, the related YEC LTA thermal displacement cost saving benefits are estimated at $286,000.

- The net effect of including LTA thermal displacement benefits in the deferral account calculations is to reduce YEC deferral costs when IPP volumes exceed approved forecasts and increase YEC deferral costs when IPP volumes fall below approved forecasts.

REFERENCE: **Application, PDF page 86**

ISSUE: IPP purchase cost deferral account

QUOTE: Although the IPP generation is predominantly in summer months, on a long-term average basis there are some benefits from IPPs to reduce thermal generation [accumulation of benefits from drought years]. Therefore, YEC is proposing to include IPP long-term average (LTA) thermal displacement benefits related to the IPP purchase volume variances in the deferral account as an offset to the power purchase cost variance.

QUESTION:

a) Please explain what is meant by the "accumulation of benefits from drought years" and describe the benefits that are referred to in the quote.

b) How will YEC prove the LTA thermal displacement benefits?

c) Does not recognizing IPP costs in the year incurred create intergenerational inequities? Please explain.

d) Does YEC agree that a GRA is a forecast of utility costs for a specific test period and that those costs should be recovered over that test period, with the exception of deferral accounts and related items? If not, why not?

ANSWER:

(a) and (b)

The reference in the quoted paragraph to the "accumulated benefits from drought years" describes the relatively greater impact that IPP generation during drought years has on reducing forecast fuel costs based on long-term averages that are required to be applied under section 9 of the Rate Policy Directive (1995), as added by OIC 2021/16.

To elaborate on this, OIC 2021/16 (s. 9(3)) requires the Board to determine YEC's forecast fuel costs for a fiscal year, for the purpose of setting YEC's rates, by forecasting the

amount of renewable generation available to contribute to customer demand based on long-term average (LTA) annual renewable source availability, and then forecasting the amount of thermal generation needed to meet any resulting shortfall. LTA annual renewable source availability is defined by OIC 2021/16 (s. 9(1)) to take into account "available information respecting other renewable generation", in addition to LTA annual hydro generation. The net effect of this assessment of LTA effects from IPP generation, having regard to data available based on YEC hydro generation historic water years, is to reduce the resulting calculation of YEC's forecast fuel costs under OIC 2021/16.

The LTA thermal generation reduction benefits related to forecast hydro and IPP renewable sources are prepared based on YECSIM model runs which is consistent with the LTA hydro and thermal generation determinations provided in Appendix 2.1. As such, given that these are forecasts, there is no actual tool to "prove" the LTA thermal generation reduction or displacement benefits from IPPs or other renewable generation sources.

Reference to the "accumulation of benefits from drought years" recognizes that LTA thermal displacement benefits are determined based on long-term averages [over 41 years of water conditions]. Although the IPP generations in the test years are predominantly in summer months when no thermal displacement benefits are expected, on a long-term average basis the benefits from IPPs to reduce thermal generation during drought years will be recognized. Without long-term average calculations, material thermal displacement benefits would not occur in most years as the IPP generations mostly displace hydro generation during normal and high-water years [i.e., the benefits from IPPs will be notably lower than 59% thermal displacement]. During lower water/drought conditions, the IPP deliveries will be used to supply the firm load and normally do not displace hydro, but help to reduce the use of thermal generation. Therefore, on a long-term average basis the IPPs that are expected to be connected to the grid by end of 2024 test year displace about 59% of thermal generation. This is consistent with the LTA hydro and thermal generation determinations provided in Appendix 2.1.

As reviewed in response to YUB-YEC-1-32(b), LTA thermal calculations are needed for the proposed IPP purchase cost deferral account only to address YEC overall net cost effects related to variances in IPP purchase volumes from approved GRA forecasts. The net effect of including LTA thermal displacement benefits in the deferral account calculations is to reduce YEC deferral costs when IPP volumes exceed approved forecasts and increase YEC deferral costs when IPP volumes fall below approved forecasts.

(c) and (d)

YEC agrees (in response to “d”) that a GRA is a forecast of utility costs for a specific test period, and that those costs should be recovered over that test period, with the exception of deferral accounts and related items. Deferral accounts, however, are required to address many different items that extend cost recoveries beyond those test periods, including balances of deferral accounts and any true-ups required to recover/refund the revenue shortfall/overcollection based on approved revenue requirements. Where deferral accounts are required, YEC agrees (in response to “c”) that intergenerational inequities can occur – but deferral accounts are nonetheless required.

OIC 2019/25 provides for utility recovery of costs related to IPPs. The proposed IPP deferral account is the only available option to address the variances in IPP costs from approved GRA forecasts due to changes in IPP deliveries and costs from what was forecast. Without the IPP cost variance deferral account, the Board would not meet its obligation under section 2 of OIC 2019/25 to set rates that allow YEC to fully recover the IPP-related costs described in section 2(2). Please see the response to YUB-YEC-1-32 (a).

The OIC 2021/16 direction confirms that all generations of ratepayers will continue to incur thermal related fuel costs based on long-term average (LTA) renewable energy source availability rather than based on varying resource availability through different time periods. The IPP deferral account only addresses the need for a mechanism to address variances from approved GRA test year forecasts.

REFERENCE: **Application, PDF page 87**

ISSUE: IPP purchase cost deferral account

QUOTE: In contrast to the 2022 situation, the overall IPP LTA thermal displacement benefits for 2023/24 GRA load is 59% of IPP purchases which is the variance of LTA thermal with and without IPPs.

QUESTION:

a) Please explain how "thermal displacement benefits for 2023/24 GRA load is 59% of IPP purchases" was determined.

ANSWER:

(a)

The LTA thermal displacement benefits of 59% were determined based on long-term average thermal requirements [over 41 years of water conditions] without and with forecast IPP EPA generation using the YECSIM model which is consistent with the LTA hydro and thermal generation determinations provided in Appendix 2.1.

The following table shows the determination of the IPP LTA thermal displacement benefits based on YECSIM model analysis. For the model assessments, YEC used the total forecast IPP EPA contract volume of 30.2 GWh based on expected IPP EPA contracts by the end of 2024. This avoids any impact from partial IPP deliveries based on in-service dates and does not have a significant impact on LTA thermal displacement assessments [for example, the model assessment with only 6.1 GWh and 16.8 GWh IPP deliveries would result in LTA thermal displacement benefits ranging between 55.5%-62.5%].

	Without IPP	With IPP EPA	Variance
Load, GWh	531.1	500.9	30.2
LTA thermal, GWh	78.5	60.9	17.7
LTA thermal as % of Incremental Load			58.5%

REFERENCE: **Application, PDF page 89**

ISSUE: Diesel rental business case

PREAMBLE: On PDF page 89, YEC lists three alternatives to the proposed short-term rental of twenty 1.8 MW diesel rental units. The alternatives are the purchase of the diesel rental units, longer term lease of the diesel rental units, and reliance on the addition of new capital facilities that are forecast to be commissioned during the GRA test years.

QUESTION:

a) Why did YEC not consider the purchase of larger diesel units and subsequent resale of those units when not required?

b) Why would YEC consider purchasing rental diesel units which YEC has already described as troublesome in past regulatory proceedings?

c) Why would YEC consider a longer term lease for rental diesel units which YEC has already described as troublesome in past regulatory proceedings?

d) Has YEC evaluated potentially more efficient and lower-cost alternatives than those referred to above? If not, why not?

e) Please provide all internal documents and analyses of the rental diesel units, including all presentations to the YEC and YDC boards of directors, any minutes from those meetings or YEC internal meetings where discussion regarding diesel rental units occurred, and any other discussions pertaining to the rental of diesel generation units.

f) Please provide all correspondence with any consultants, any terms of reference, and all products of any analysis regarding the rental of diesel generation units.

ANSWER:

(a), (b), and (c)

YEC's consideration of the potential purchase and resale of diesel units as outlined in Appendix 3.1 of YEC's Application did include consideration of the possible purchase of new units (which would include "larger" units) alongside the option of purchase and resale of the existing diesel rental units.

The list of three broad alternatives to the proposed short-term rental of twenty 1.8 MW diesel rental units, excluding spares, for the 2023-2024 test years was scoped to address the alternatives raised by the Board in the direction given at paragraph 115 of Appendix A of Board Order 2022-03.

- The "own/resale" and "lease" options were considered in relation to the rental diesel units to ensure that the review covered all of the alternatives noted, notwithstanding past evidence as to why such alternatives were not feasible or attractive for YEC.

- However, YEC's consideration of the "own/resale" option also included the potential purchase of other new diesel units to replace or expand YEC's existing diesel generation facilities. In particular:

    - YEC explains on page 3.1-3 of Appendix 3.1 that the purchase option for new diesels is only available subject to the time needed to complete required prudent planning and implementation activities, and that planning for such a purpose requires considerable time for design, procurement and installation.

    - The issues set out at the end of Appendix 3.1 (on page 3.1-7) relating to the financial risk created by the "own/resale" option also apply broadly across new diesel unit options, regardless of the size of the units. For example, based on current information, the LCOC for new units sold in the 11th year after commissioning is far higher than the rental option unless YEC will be able to sell the units at unrealistically high sales prices. Such a risk is simply not reasonable or prudent.

- YEC's comments in Appendix 3.1 also necessarily distinguish between short-term planning to meet N-1 dependable capacity requirements for the 2023 and 2024 test years (i.e., the business case focus for the current test year diesel rentals), and YEC's longer-term dependable capacity planning options.

- YEC's discussion of the alternative to add new capital facilities that could be commissioned in the test years focuses on specific projects being undertaken, but also describes experience to date on the practical constraints related to timing and planning for committing and commissioning major capital expenditures.

    - These constraints make it impracticable for YEC to plan adding new permanent diesel generation facilities that could be commissioned in the test years beyond the 12.5 MW of diesel replacement facilities at Whitehorse, Faro and Dawson specified in the 10-Year Renewable Electricity Plan and planned for in-service during winter 2023/24; during implementation of this plan, however, YEC was also able to add 4 MW of additional diesel at Dawson City that will result in 6.5 MW of new diesel capacity in that community (the initial planned 2.5 MW replacement unit was replaced by a 3.25 MW unit based on equipment availability, and a second 3.25 MW unit was added as part of the project to support back-up power in that community based on growing demands).

    - These constraints also delayed commissioning of the BESS and the new diesel projects as reviewed in Section 5.1A-1 of Appendix 5.1A, requiring YEC to arrange for additional rental diesels for the test years.

    - These constraints, however, did not prevent YEC from securing new diesel units larger than the 1.8 MW diesel rentals, i.e., all new units were initially planned at 2.5 MW and, due to availability issues, the recent planning adjustment will secure two 3.25 MW new diesel units at Dawson City.

(d)

YEC has reviewed all possible options in its planning work. This has been documented for the Board in recent BESS and Atlin EPA proceedings as well as in YEC's ongoing GRA applications.

YEC continues to evaluate potential options to enhance system reliability, efficiency and affordability, considering Yukon's Our Clean Energy Future strategy (that the Yukon government plans to develop legislation to require at least 93% of the energy generation on the YIS to come from renewable sources every year starting in 2030).

The 2023-2024 GRA updates information on new diesel installations that address the separate requirements of different Yukon communities as well as overall YIS requirements.

In response to the Board's specific question, planning work to date has not identified more efficient or lower cost alternatives that are acceptable and/or implementable for the 2023-2024 GRA test years. Given the factors and considerations reviewed in response to YUB-YEC-1-36, YEC is not aware of any more efficient and lower-cost alternatives for the test years than those considered in Appendix 3.1.

(e) and (f)

These requests are far too broad and lack sufficient definition that would allow YEC to gather and produce relevant information in the time available for YEC to respond to the IRs -- especially given YEC's ongoing work for many years on diesel rentals and other potential resource options. Further, the issue of rental diesels as a resource option has been before the Board on numerous occasions and significant material on this issue has been provided in this and previous proceedings. For example, related information on current diesel rentals relevant to the Application have been provided separately in this proceeding in the following responses: YUB-YEC-1-1; YUB-YEC-1-24; YUB-YEC-1-36; YUB-YEC-1-37; YUB-YEC-1-38; YUB-YEC-1-39; YUB-YEC-1-40; YUB-YEC-1-41; YUB-YEC-1-42; YUB-YEC-1-43; YUB-YEC-1-44; YUB-YEC-1-47; YUB-YEC-1-48; YUB-YEC-1-49; NY-YEC-1-8; NY-YEC-1-9; NY-YEC-1-19; NY-YEC-1-20; NY-YEC-1-21; NY-YEC-1-22; NY-YEC-1-23; NY-YEC-1-24; and JM-YEC-1-3.

The following responses in this proceeding also address updates regarding resource planning; the BESS and the Atlin EPA: JM-YEC-1-5 and NY-YEC-1-5 (provide updates regarding the BESS Project); JM-YEC-1-7; NY-YEC-1-6; NY-YEC-1-7 (provide updates regarding the Atlin EPA; SLESP; MLESP and Tutshi-Moon pumped storage project).

Prior proceedings on the Battery Energy Storage System (BESS), the Atlin EPA and earlier GRAs, as well as other responses in the current proceeding, have also provided significant details on YEC resource planning activities.

- CW-YEC-1-36(a) Attachment 1 from the 2021 GRA provided a copy of YEC's 10-Year Renewable Electricity plan completed during 2020. CW-YEC-2-6 from that proceeding reviewed at a high level the assessment of options to displace reliance on rented diesels; and alternatives considered.

- The Response to YUB-YEC-1-36 (b) and (c) from the Atlin EPA proceeding provided a summary of the relevant record at that time related to the investigation of thermal generation options; and provided a summary of relevant information regarding the following:
    - Rented diesels as a feasible option for near-term capacity shortfall;
    - Renting option is preferrable to possible ownership that assumes subsequent sale.

  This response was reviewed in detail and provided relevant references to both the BESS Proceeding and the 2021 GRA proceeding [including reference to relevant information requests, and transcript reference where these issues are discussed].

It needs to be emphasized that YEC is continually assessing options to reduce the need for rental diesels, and that currently available specifics regarding each non-rental option are discussed in this Application.

YEC also notes that documentation provided to its board (including minutes of board meetings and board resolutions) or to the Yukon Development Corporation's board has never been provided in previous YUB proceedings for many reasons, including most importantly board confidentiality.

REFERENCE: **YEC-Tlingit Homeland Energy LP (THELP) Energy Purchase Agreement (EPA) Proceeding, Report to Yukon Minister of Justice, PDF pages 11 and 37-40; Application, Appendix 3.1, PDF pages 89-95**

ISSUE: Diesel rentals

QUOTE: YEC-THELP EPA Proceeding, Report to Yukon Minister of Justice, PDF page 11:

> However, YEC has been renting diesels since 2016 and expects to be renting diesels past 2030. Renting for at least 14 years is not a short-term event or solution. YEC has not shown the rentals to be a least-cost solution on a short term or long-term basis. Although these costs were accepted in the 2021 GRA, YEC will need to show the least cost thermal alternative of rentals versus permanent thermal at the time of its next GRA or risk finding that those diesel rental costs were imprudently incurred.

YEC-THELP EPA Proceeding, Report to Yukon Minister of Justice, PDF pages 37-40:

> YEC then pursued permanent diesel solutions including a 20 MW diesel plant, which was included in its 2017-18 GRA. Based on the evidence from YEC, it was prepared to proceed with the permanent thermal plant at that time. In the decision to that GRA dated December 27, 2018, the Board noted that YEC supported its case that adding capacity is needed but that YEC did not provide a sufficient business case to support the project. Had YEC done so, the thermal plant could have been in place by 2021 and the well-documented shortcomings of rented diesels would not be a recurring issue in each of YEC's subsequent regulatory proceedings before this Board. As a result of the poor business case, YEC put itself in the position of having no other viable option at the time to obtain capacity other than renting diesel units. (Footnotes omitted.)

> The Board notes that instead of resubmitting a proper business case regarding the 20 MW diesel option, YEC, at the direction of its board, went in a different direction, thus cementing its reliance on the diesel

> rental option. In the Board's opinion, had THELP not approached YEC regarding the Atlin project and potential EPA, YEC would not have had any other options regarding a resolution to its capacity shortfall. In addition, YEC has not set up any RFP for new projects, renewable or otherwise, and has not provided any evidence that it has moved forward on any of the renewable projects it identified in either its 2016 Resource Plan or 10-Year Renewable Electricity Plan.
>
> …
>
> Further, the Board is of the view that YEC's assumption that it would need to buy and sell diesel-generating units on an annual basis is unsupported. YEC could acquire a unit to meet its capacity shortfall requirement until a permanent renewable solution is in place. Then when the unit is not required, YEC can either shift the unit to replace retiring units or sell the unit. Since the unit is intended for capacity purposes, the hours of run time would likely not be significant. To reduce uncertainty, YEC could go to the market to estimate the future value of the diesel unit it wants to sell; such a market exists. The Board noted that, for its initial submission regarding the Minto PPA (Purchase Power Agreement), YEC proposed to purchase the "used" diesel unit that Minto acquired for electricity until the mine was connected to the grid.
>
> Although the Board agreed with the rental of diesel-generation units on an urgent short-term basis for YEC's 2021 GRA, the evidence of YEC in this proceeding is that the diesel rentals are not a good solution and that the need for additional capacity is for more than the near term. The Board does not accept that YEC provided sufficient evaluation or investigated the permanent diesel-generating unit alternative. It appears that since the initial rental agreement and the ensuing problems with the rental diesel units, YEC has not explored any other options to address the shortfall prior to the forecast renewable energy projects being brought on.

QUESTION:

a) Given the concerns expressed by the Board in the YEC-Tlingit Homeland Energy LP Energy Purchase Agreement Proceeding, Report to Yukon Minister of Justice, how does YEC's business case address those concerns?

ANSWER:

(a)

YEC's business case for diesel rentals must be considered in light of the following:

- In the 2021 GRA, the Board accepted the cost of short-term diesel rentals and approved the inclusion of those costs in YEC's revenue requirement for the 2021 test year.

- It was in the context of that approval that the Board went on to direct YEC to provide a specific business case *going forward* for the diesel units in its next GRA. This was not a direction to provide a business case revisiting previously incurred diesel rental costs that were already approved by the Board for the 2021 test year. The only reasonable interpretation of the Board's direction was that YEC would be expected to provide a business case to support its continued use of diesel rental units in the 2023 and 2024 test years, going forward from the baseline of YEC's approved 2021 rate base.

- Regardless of the Board's views today about whether or not the "renting [of diesel units] for at least 14 years" can be seen as a "short-term event or solution", that is not the question that is before the Board in the current proceeding. It is not the Board's role in this proceeding to revisit the costs that were previously approved by the Board for diesel rental units in previous GRAs. Rather, the question for the Board in this proceeding is whether YEC has provided sufficient evidence to establish the prudency of the diesel rental costs that it projects it will continue to incur for the 2023 and 2024 test years, having regard to the options available to YEC going forward from the existing state of affairs in 2021 in order to satisfy peak demand and to meet the N-1 dependable capacity requirement for the 2023 and 2024 test years.

Having regard to the foregoing, YEC's business case for diesel rentals confirms that, going forward from 2021, diesel rentals are the only feasible option to supply the dependable capacity that is needed to ensure a reliable supply of electricity to YEC's ratepayers during the current GRA test years. The business case also reviews:

- How test year costs for these rentals remain reasonable relative to costs being revealed for test year new diesel installations;

- How YEC is moving forward today with thermal displacement and new dependable thermal projects to meet longer-term planning needs; and

- How YEC is also carrying out a review and update of its 10-Year Renewable Electricity Plan to address other concerns identified by the Board.

YEC's business case reflects the reality set out in the Board's above-noted report regarding the clear need for diesel rentals for the GRA test years 2023 and 2024, after taking into account all installed and forecast dependable capacity facilities on the YIS for the test years, in light of the earlier decision not to proceed with the 20 MW diesel plant, which was taken after planning and public engagement on that option.

YEC's business case also reviews projects currently being implemented to provide permanent dependable capacity and renewable energy for the test years as proposed in the 10-year Renewable Electricity Plan, including new diesel replacement units, the BESS project, capacity-related DSM, and the Atlin EPA renewable dependable capacity and energy project reviewed in the Board's above report. YEC work on these projects has involved extensive activity and utilization of available resources, and, as reviewed in the current Application's business case for the Thermal Replacement Project (Section 5.1A-1), has displayed continuous evaluation and evolution of implementation details for each project that will enhance future project option assessments and implementation.

The business case further reports with regard to future project activity that YEC is currently completing a review and update of the 10-Year Renewable Electricity Plan to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro Project. This review will consider learnings from YEC project development during the past few years to identify and assess next stage project installations that will reduce the need for thermal rentals.

REFERENCE: **Application, PDF pages 89 and 157; Appendix A to Board Order 2018-10, PDF page 94**

ISSUE: Diesel rental business case and thermal replacement project

QUOTE: Application, PDF page 89:

In considering the short-term rental and longer-term lease or "own/resale" alternatives, it is necessary to distinguish between the need for diesel units to satisfy the N-1 dependable capacity requirement during the 2023/2024 GRA test years, versus YEC's ongoing planning to address future dependable capacity requirements in the longer term. Diesel rentals are proposed to address short-term requirements during the test years, and not as a long-term plan for providing YEC's required dependable capacity.

Appendix A to Board Order 2018-10, PDF page 94:

The Board is of the view that YEC has supported its case that adding capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity. However, YEC has not provided a business case in support of this project. YEC did not detail the costs and benefits associated with this project. The Board finds that it is not reasonable for YEC to proceed with the project without a detailed business case that considers the alternatives to the project. The Board notes that YEC forecast costs for 2019 and 2020 of $38 million and $20 million respectively. The magnitude of these costs alone is reason for proceeding cautiously. The Board is not persuaded that this project is the only way to address the predicted capacity shortfall and that the forecast costs are reasonable. The Board requires a detailed evaluation of alternatives to this project included in the business case.

Application, PDF page 157:

The Thermal Replacement project will install and commission in 2024 two 2.5 MW US Environmental Protection Agency (EPA) Tier 4 modular diesel units at the Faro diesel plant to replace 2023 retirement of Faro Diesel 1 (FD1) (5.1 MW); this new 5 MW of thermal dependable

capacity will displace the need to rent three additional 1.8 MW diesel units for winter 2024/25, and add approximately $18.2 million to YEC's 2024 year-end rate base.

QUESTION:

a) Please explain why YEC distinguishes short term from long term for diesel generator rental unit purposes but considers LTA thermal displacement benefits for an IPP deferral account.

b) Please describe the role that YEC's consultants played in the development of the diesel rental unit business case.

c) Please provide the rationale in support of YEC's view that the rental of diesel generator units is a short-term option, given that the diesel generation units have been rented at least since 2016 and are forecast to be rented well into the future.

d) The referenced plant (5 MW – two 2.5 MW units for Faro) has a planned in-service date of winter 2024-25. Please provide a table showing the revenue requirement costs on an annual basis if that plant is put into service by 2024, showing separate columns for: undepreciated capital at the beginning of the year, return, depreciation, undepreciated capital cost at the end of the year, maintenance costs, and any other cost information shown separately and deemed relevant for its planned 40-year service life.

e) What are the characteristics of a US Environmental Protection Agency (EPA) Tier 4 modular diesel unit? Distinguish the characteristics from those of a Tier 1, 2, 3, or 5 modular unit.

f) What are the price differences on a per-MW basis between units of each tier?

g) Do all of the rented diesel generation units used by YEC comply with US EPA Tier 4 modular diesel units standards? Please explain.

h) How do the diesel rental units compare with the characteristics of a US EPA Tier 4 modular diesel unit?

i) Are the capital costs for the Faro diesel replacements scalable? That is, for a larger unit, would the capital cost related to the purchase of the unit on a per-MW basis be lower than a 2.5 MW unit? Please explain.

j) Please explain why YEC did not consider individual 5 MW units for replacement purposes.

k) If larger diesel units do not provide economies of scale, then why would any utility or location ever acquire a unit above 1.8 to 2.5 MW capacity instead of simply acquiring a series of 1.8 to 2.5 MW units?

l) In theory, do diesel units provide economies of scale — that is, the larger the unit, the lower the cost per MW should be?

m) If economies of scale apply for larger thermal units, please provide the same cost information showing annual costs as requested in part (d) but for two 10 MW diesel generation plants with an in-service date commencing January 1, 2025. Clearly state the reference for how the initial capital costs are obtained.

n) For parts (d) and (e), show the potential sale prices of the diesel units after 10 years of service, 15 years of service, and 20 years of service.

ANSWER:

(a)

Diesel rentals are an expense and, based on rental terms, are therefore described as "short-term". Further, the referenced statement from the Application highlights the need for diesel rental units to satisfy the N-1 dependable capacity requirement during the 2023/2024 GRA test years as diesel rentals are proposed to address short-term requirements during the test years, and not as long-term plan for providing YEC's required dependable capacity. The referenced statement mentions possible "lease" or "own/resale" alternatives - and simply notes that these are defined to have a longer term than the diesel rentals, i.e., no suggestion is made that these are being viewed as "long-term" options. The discussion of diesel rentals or lease also does not address forecast diesel energy generation overall for the test years, i.e., forecast diesel energy generation overall is forecast, as required by OIC 2021-16, based on long-term averages.

In contrast, IPPs are long-term agreements to provide renewable energy. Accordingly, for rate setting purposes (including the IPP deferral account) the IPP thermal displacement benefits are forecast on a LTA basis, as required by OIC 2021-16. Please see response to YUB-YEC-1-33 for detailed information.

(b)

InterGroup Consultants assisted in developing and finalizing the diesel rental business provided in Appendix 3.1.

(c)

Generally, YEC defines short term for planning purposes as up to 10 years, and diesel rental planning to date has had this focus, i.e., YEC has never planned to commit a diesel rental agreement for more than ten years and has not planned to rely on diesel rentals as a long-term solution to dependable capacity requirements.

Notwithstanding this short-term planning focus, events can unfold such that diesel rental requirements end up being required for a longer time period than was originally planned. YEC's planning response to this situation, however, continues to view diesel rentals as only a short-term option for dependable capacity requirements.

YEC is continually assessing options to reduce the need for rental diesels, including evaluating potential options to enhance system reliability, efficiency and affordability, taking into account Yukon's Our Clean Energy Future strategy (that the Yukon government will develop legislation to require at least 93% of the energy generation on the YIS to come from renewable sources). Prior proceedings on the Battery Energy Storage System (BESS), the Atlin EPA and earlier GRAs, as well as other responses in the current proceeding, have discussed details of YEC resource planning activities in this regard.

As indicated in the response to YUB-YEC-1-1 (a)-(c), Yukon Energy is developing an Electricity Supply Plan that will develop a revised workplan for the next 5-10 years for meeting electricity demand during winter peak and N-1 events. The Electricity Supply Plan is expected to be released by mid-2024. It will consider the status of projects proposed in the 10-Year Renewable Electricity Plan and outline a workplan to plan to meet Yukon's electricity needs in the next 10 years. Yukon Energy is also developing an updated long-term plan under the Resource Plan that will determine Yukon's long-term electricity needs

and identify resources that are best suited to meet those needs. The Resource Plan is scheduled to be complete in late 2025.

(d)

Please see YUB-YEC-1-37 Attachment 1 which shows estimated annual costs for the project over 40 years.

The 2024 test year does not include depreciation expense for the project [the GRA assumes the depreciation starts in 2025], therefore, no depreciation expense is shown in the attachment for 2024.

(e)

The U.S. Environmental Protection Agency (EPA) Tier 4 regulations for diesel engines significantly reduce emissions of particulate matter (PM) and nitrogen oxides (NOx) compared to the earlier Tier 1, 2, and 3 standards. Here's a breakdown of the characteristics of a Tier 4 modular diesel unit, compared to Tier 1, 2, and 3 units:

Tier 4 Modular Diesel Unit:

- Emission Reduction: Tier 4 engines use advanced technology to reduce PM and NOx emissions by up to 90% compared to Tier 3 standards.

- Technology Used: Incorporates advanced features like high-pressure common-rail fuel systems, advanced turbocharging, exhaust gas recirculation (EGR), diesel particulate filters (DPF), and selective catalytic reduction (SCR).

- Fuel Efficiency: Generally, more fuel-efficient due to advanced engine technologies.

- Ultra-Low Sulfur Diesel (ULSD): Requires ULSD fuel to operate effectively and protect the engine's sophisticated components.

Tier 1, 2, and 3 Modular Diesel Units:

- Progressive Emission Standards: Each tier represented progressively stricter emission standards. Tier 1 started in 1996, Tier 2 in 2001, and Tier 3 in 2006.

- Technology: Earlier tiers focused on less advanced technologies. Tier 3 began the introduction of technologies like EGR but did not require DPF or SCR systems.

- Fuel Efficiency and Emissions: These units are less fuel-efficient compared to Tier 4 and produce higher levels of PM and NOx.

- Fuel Requirements: These earlier tiers did not require ULSD.

(f)

The exact price difference per MW will vary based on specific models and manufacturers.

Based on quotes received by YEC, the price difference between Tier 2 and 4 units for the installation of 12.5 MW units was about $3 million [Tier 4 higher than Tier 2].

YEC is not obligated to install EPA Tier 4 rated diesel engines since there is an exemption for remote/islanded communities. However, YEC decided to go with the selection of EPA Tier 4 engines based on the following:

1. Selection of Tier 4 engines with reduced particulate and nitrous oxide/sulphur oxide (NOx/SOx) emissions will reduce air emissions and reduce environmental impact for the local communities in Whitehorse, Faro Dawson. As such, the selection of Tier 4 engines is aligned with YEC's corporate commitment to following Environment, Social and Governance (ESG) best practices and minimizing impacts of our operations.

2. Selection of lower emission Tier 4 engines will assist with the renewal of the air emissions permit for WRGS which is required to run 16 MW permanent generation and 12 MW rental diesels, allowing YEC to maximize the amount of thermal generation that can be permitted under the worst-case meteorological conditions.

3. As part of the permitting of thermal generation at the Faro site, Yukon Government raised concerns about the NOx emissions under worst-case meteorological conditions. As a result, under the new permit, YEC is required to develop and

implement an air quality monitoring plan for the Faro site. Installing an EPA Tier 4, 5 MW diesel engine in Faro will alleviate some of these concerns regarding NOx emissions.

(g) and (h)

No. The rental gensets do not comply with the US EPA Tier 4 standards, generally they are Tier 2. This is permissible in many regions for temporary or mobile diesel gensets and there is an exemption for remote/islanded communities.

Please also see the response to (e).

(i), (l) and (m)

The scope of the Diesel Replacement Project is installing new diesel units to replace the retiring diesel units in Whitehorse, Faro and Dawson. The communities of Faro and Dawson rely on the diesel plants in their communities to supply backup power year-round. Should the transmission line connecting one or both of the communities be taken out of service due to an outage on the line or for maintenance or repairs, the diesel generators must be available to provide backup power.[1] Therefore, no quotes were obtained for building/installing a 5 MW, 10 MW or 20 MW diesel plant.

Although the average cost per MW would be lower for larger-sized diesel engines due to economies of scale, there are other incremental costs that would impact the economics of the options as a larger unit will require a building for the installation rather than being able to rely on modular units. For example, an assessment work that was completed in 2021 concluded that significant upgrades would be required to mitigate the risk of soil liquefaction during a seismic event and to bring the Whitehorse Generation Station (WRGS) P126 building into compliance with the National Building Code of Canada. At that time the costs of these upgrades were estimated at about $5 million, which would materially impact the economics of the thermal replacement at the Whitehorse facility. Therefore, in November 2021, the YEC Board approved the removal of the P126 renovation from the scope of the project at the Whitehorse location, and instead approved

[1] Due to the isolated nature of the Yukon grid, the priority in the planning was given to make sure the communities have sufficient capacity in case of transmission outages and also provide operational flexibility as noted in response to (j).

a plan to procure and install a containerized or 'packaged' modular thermal plant at the WRGS facility. A similar issue exists with the existing FD1 building which would require significant investments bringing it up to the 2020 National Building Code of Canada.

Please also see the response to (j) below for the rationale YEC chose to go with smaller units.

(j)

YEC was seeking a modular solution instead of installing units in buildings to manage the scope, cost, and schedule. A larger 5 MW unit rated for continuous operation will require a building for the installation. The cost of renovating the existing FD1 building and bringing it up to the 2020 National Building Code of Canada (NBCC) would add more cost and time to the project budget and schedule, respectively.

The modular solution also allows the units to be built and commissioned offsite before shipping to the site for final assembly and commissioning. This helps to manage labour and material costs and technical challenges with commissioning.

The smaller modular units also provide operational flexibility as installing two 2.5 MW units instead of one 5 MW provides higher generation availability. With two units, if one unit goes down then there is still 50% generation availability while one 5 MW unit would have 0% generation availability if it is taken out of service for maintenance or repairs. In addition, the modular units' scale provides operational flexibility suited to expected thermal generation requirements on the Yukon Integrated Grid (YIS) for peaking, back-up and emergency use rather than for base load high utilization use.

(k)

Each grid or utility has its own unique condition that requires specific planning regarding the size of the required plant. Some utilities use larger plants to provide base load in the load center while having smaller units as backup.

However, due to the isolated nature of the Yukon grid, the Diesel Replacement Project scope for the YIS was to make sure the different communities have sufficient capacity in case of transmission outages and also provide operational flexibility as noted in response to (j), i.e., with two units generation availability increases compared to one larger unit, and

also provides greater flexibility to address expected diesel energy requirements on the YIS with its dominant renewable energy generation capability.

The selection of new smaller diesel units (rather than larger sized units) is shown in isolated northern thermal zone communities. For example, in Nunavut, Qulliq Energy Corporation, a utility with 25 isolated communities, submitted a new power plant option application in 2021 for Cambridge Bay that proposed five separate units ranging between 0.850 MW and 1.350 MW for a total of 5.5 MW installed capacity [total cost at $50.237 million in 2021$]. Similar options were proposed by the utility for Gjoa Haven [four units for a total of 3.1 MW capacity], Igloolik [four units for a total of 3.45 MW capacity] and Arctic Bay [four units for a total of 1.6 MW capacity] communities.

(n)

Please see the responses to YUB-YEC-1-42 (a), YUB-YEC-1-48 (a) - (b) and (d).

Diesel Replacement Options - Faro 5 MW

YEC 2023/24 GRA
YUB-YEC-1-37 Attachment 1

Weighted Average Cost of Capital	6.018%
Inflation Rate	2%

Winter MW		**5.00**	
Capital ($000)	2024	$18,175	
Fixed O&M	2020	$85	$000/yr
Assumed Life		**40**	years

Year	Diesel Replacement Options - Faro 5 MW				
	Year-End Balance $000	Depr $000	Return $000	Estimated Fixed O&M $000	Total $000
2024	18,175		547		547
2025	17,721	454	1,080	94	1,628
2026	17,266	454	1,053	96	1,603
2027	16,812	454	1,025	98	1,577
2028	16,358	454	998	100	1,552
2029	15,903	454	971	102	1,527
2030	15,449	454	943	104	1,501
2031	14,994	454	916	106	1,476
2032	14,540	454	889	108	1,451
2033	14,086	454	861	110	1,426
2034	13,631	454	834	112	1,401
2035	13,177	454	807	114	1,375
2036	12,723	454	779	117	1,350
2037	12,268	454	752	119	1,325
2038	11,814	454	725	121	1,300
2039	11,359	454	697	124	1,275
2040	10,905	454	670	126	1,251
2041	10,451	454	643	129	1,226
2042	9,996	454	615	131	1,201
2043	9,542	454	588	134	1,176
2044	9,088	454	561	137	1,152
2045	8,633	454	533	139	1,127
2046	8,179	454	506	142	1,102
2047	7,724	454	479	145	1,078
2048	7,270	454	451	148	1,054
2049	6,816	454	424	151	1,029
2050	6,361	454	396	154	1,005
2051	5,907	454	369	157	981
2052	5,453	454	342	160	956
2053	4,998	454	314	163	932
2054	4,544	454	287	167	908
2055	4,089	454	260	170	884
2056	3,635	454	232	173	860
2057	3,181	454	205	177	836
2058	2,726	454	178	180	813
2059	2,272	454	150	184	789
2060	1,818	454	123	188	765
2061	1,363	454	96	191	742
2062	909	454	68	195	718
2063	454	454	41	199	695

Notes:

1. Faro diesel replacement cost as per Table 5.1A-1.1 in Tab 5.
2. Weighted average cost of capital is based on proposed ROE at 8.70% and new long term debt cost at 4.23%.
3. Fixed O&M estimate is based on 10-Year Renewable Electricity Plan [$0.170 million/year for 10 MW or $0.085 million/year for 5 MW].
4. The 2024 Test Year does not include depreciation expense for the project.

REFERENCE: **Application, PDF page 90**

ISSUE: Rented diesels

QUOTE: Diesel infrastructure at Whitehorse, Faro and Mayo has been or is being established to accommodate the needed modular diesel units.

QUESTION:

a) Please provide the annual diesel infrastructure costs and forecast costs by location and by year for each of the years 2014 to 2030.

ANSWER:

(a)

The rental diesel infrastructure costs are not annual costs, but one time capital costs to accommodate diesel rentals.

- Whitehorse rental diesel infrastructure with capital spending in 2018 and 2019 years with a total cost of $1.298 million was added to rate base [YUB Order 2022-03, para 250].

- Faro rental diesel infrastructure with capital spending in 2020 year with a total cost of $2.446 million was added to rate base [YUB Order 2022-03, para 250].

- Mayo-Faro diesel infrastructure cost of $4.3 million is proposed to be added to rate base in 2023 (Section 5.1A-2 in Application). This infrastructure for mobile and modular diesel units facilitated planned and potential new permanent diesel units as well as rental diesels.

YEC does not have cost estimates for future rental connections. YEC expects that with new renewable capacity projects, no new rental site would be required. Please see the response to YUB-YEC-1-1 for forecast diesel rentals.

REFERENCE: **Application, PDF page 91**

ISSUE: Rented diesels

QUOTE: New capital facilities commissioned in 2024 will be included in the 2023/24 GRA revenue requirement rate base only to the extent that diesel rentals for winter 2023/24 and 2024/25 can be reduced.

QUESTION:

a) Are the facilities to be commissioned in 2024 referenced above forecast to be part of rate base in 2024 in this Application? Please explain.

b) If these facilities are not forecast to be part of rate base in this Application, how do they become part of revenue requirement when the decision in this proceeding sets the revenue requirement? Please explain.

c) Please confirm that the proper test for new facilities to be included in rate base is the completed construction of a “used and useful” utility asset. If not confirmed, please explain.

d) Generally, are YEC’s practices to put assets in rate base compliant with the test described in part (c) above? Please explain.

ANSWER:

(a)

No.

The quoted reference to new capital facilities to be commissioned in 2024 on page 3.1-3 of Appendix 3.1 is intended to refer to the BESS project and 6.5 MW of new Dawson diesel capacity. YEC has not included either of those items as part of its forecast rate base in 2024 in this Application, i.e., the Application assumes that both the BESS and Dawson diesel replacement projects are forecast to remain in WIP.

(b)

The above-referenced quote is included in a bullet that acknowledges the possibility that the BESS and/or new Dawson diesel dependable capacity being commissioned in 2024 might be confirmed as being reliable during all of winter 2024/25, and that this confirmation might occur soon enough in 2024 (i.e., before approximately June 2024) to enable cancellation of approximately equivalent diesel rental capacity. Otherwise, the bullet notes that YEC must retain diesel rentals in winter 2024/25 as currently planned.

If YEC can reduce its forecast requirement for rented diesels prior to the Board's GRA hearing due to confirmed BESS and/or new Dawson diesels, YEC will propose to the Board that the revenue requirement for the 2024 test year be adjusted to exclude the removed diesel rentals and include the commissioned additional dependable capacity that enabled the reduction of diesel rentals.

To be clear, no matter how events unfold in 2024, YEC will not change (and has not proposed to change) its revenue requirement for the 2024 test year (i.e., the regulated forecast revenue requirement used to set approved rates) after the Board has concluded its hearing and closed the evidentiary record for this proceeding, let alone after the Board's decision on this Application.

(c)

Confirmed.

(d)

Yes. The Application confirms YEC practice to put assets in rate base during a GRA proceeding that are forecast to be used and useful. The BESS and Dawson diesel replacement units are forecast to be commissioned in 2024, and therefore to become used and useful assets on the Yukon grid. Nonetheless, the Application does not currently forecast these capital assets to be included in the Application's 2024 rate base. The response to "b" above clarifies the only conditions under which these capital assets would be proposed to be included in the Application's 2024 rate base.

REFERENCE: **Application, PDF page 91**

ISSUE: Rented diesels

QUOTE: The purchase option for new diesels is only available subject to the time needed to complete required prudent planning and implementation activities, i.e., YEC is already making maximum use of new purchase diesels to displace the need for rental diesels in the test years.

QUESTION:

a) Why has YEC delayed the planning or the purchase option until this Application? Please provide a detailed explanation.

ANSWER:

(a)

YEC has not, with respect to thermal generation capacity, “delayed the planning or the purchase option until this Application.”

Purchase of new thermal (diesel or LNG) has been continuously assessed in past planning work, addressing replacement of retiring thermal units with LNG or diesel purchases, looking at the option of a major new diesel plant (which option was rejected after detailed planning and public engagement), and addressing the need for expanded thermal where needed to meet local load growth (recent Dawson diesel expansion commitment).

In the current resource plan context, the 10-Year Renewable Electricity Plan sought to develop large scale new renewable dependable capacity with a pumped storage hydro plant at Moon Lake – and purchase of new thermal today and in the short-term was determined in this context to be adequate in the long-term when limited to replacement of retired diesel units.

Overall, YEC is continually assessing options to reduce the need for rental diesels, including evaluating potential options to enhance system reliability, efficiency and affordability, taking into account Yukon’s Our Clean Energy Future strategy (that the

Yukon government will develop legislation by 2023 to require at least 93% of the energy generation on the YIS to come from renewable sources). Prior proceedings on the Battery Energy Storage System (BESS), the Atlin EPA and earlier GRAs, as well as other responses in the current proceeding, have discussed details of YEC resource planning activities in this regard – including YEC's current work on an Electricity Supply Plan to update the 10-Year Renewable Electricity Plan and develop a revised workplan for the next 5-10 years for meeting electricity demand during winter peak and N-1 events.

More details are provided in the responses to YUB-YEC-1-1 (a)-(c), YUB-YEC-1-37 (c), YUB-YEC-1-41 (a).

REFERENCE: **Application, PDF page 91; YEC BESS Application, PDF page 9**

ISSUE: Rented diesels

QUOTE: Application, PDF page 91:
As indicated for the test years, delays in commissioning the BESS and 11.5 MW of new diesels committed at Dawson and Whitehorse have materially increased the 2024 diesel rental requirement.

BESS Application, PDF page 9:
In order to have the Project in service by November 2022 (i.e., available for winter 2022/23), long lead BESS and related equipment need to be ordered by approximately mid-2021 and initial site preparation activities also need to be completed in August 2021.

QUESTION:

a) Please explain the reason for the delays in commissioning the new diesels at Dawson and Whitehorse.

b) The Battery Energy Storage System (BESS) project is forecast to be commissioned during 2024, but the expected in-service date was November 2022. Please provide a detailed explanation of the reasons for this delay.

ANSWER:

(a)

The Thermal Replacement Project experienced delays primarily due to challenges in the global supply chain and manufacturing issues. This situation impacted the procurement of generator sets (gensets) for various locations under the project. Initially scheduled for timely deployment, the acquisition of these essential components faced setbacks as the manufacturing and delivery timelines extended beyond the project's original schedule. To mitigate these delays, particularly for the Dawson site, YEC adapted its approach by altering the project's scope. The new strategy opted to procure higher capacity gensets that were already manufactured and available, aiming to keep the project's completion as close to the planned timeline as possible. This decision was a strategic response to the

unforeseen external challenges, reflecting the dynamic and adaptive management required in large-scale infrastructure projects amidst a fluctuating global supply landscape.

(b)

The Battery Energy Storage System (BESS) project experienced significant delays, primarily due to a confluence of factors that extended beyond the initial timelines. A key reason for the postponement was the prolonged process in finalizing the terms and conditions following the contract award signing with the Engineering, Procurement, and Construction (EPC) contractor. This delay was further exacerbated by supply chain disruptions and a rapid escalation in material costs, a consequence of post-COVID inflationary pressures. These economic changes significantly impacted the cost structure of the project, leading to increased expenses for raw materials and subcontracting services. To address these unforeseen challenges, a change order was issued to extend the contract duration. This revision was necessary to accommodate the additional time needed to navigate the complex landscape of increased costs and supply chain hurdles, ensuring that the project could proceed despite the existing challenges faced by the main EPC contractor. The cumulative effect of these factors played a pivotal role in pushing the project's completion timeline beyond its original schedule.

REFERENCE: **Application, PDF page 92**

ISSUE: Diesel rental units

QUOTE: Furthermore, at time of such purchase, there is no apparent feasible option to lock down a time and acceptable price for future sale of the new unit.

QUESTION:

a) Does YEC use estimates in any of its GRA forecasts?

b) How were the costs for the 20 MW thermal units in YEC's 2017 GRA determined?

c) How were the costs of the BESS project in the BESS project proceeding determined?

d) What could YEC have done to estimate a future sale price of the diesel units?

ANSWER:

(a) and (d)

Yes, YEC uses forecasts/estimates in its GRA filings. For major capital projects forecast to be in rate base during GRA test years, "forecasts/estimates" in a GRA typically reflect contract arrangements with external parties that lock down terms to develop and commission the projects, with specific costs and timelines.

The above quote, however, highlights critical differences affecting any future sales price "estimate" that might be provided for a diesel unit forecast to be commissioned during a GRA test year. At the time of YEC purchase and commitment of a new diesel unit, there is no apparent feasible option "to lock down a time and acceptable price for future sale of the new unit". Any such sale prices in a GRA for the diesel units being commissioned at that time would have to look about 10 years into the future with considerable uncertainty as to timing for any future YEC sale let alone a likely price at the time of such sale.

A future sale price of the diesel units would need to be estimated based on available information when the estimate is prepared. However, unlike capital cost estimates that get refined under needed contracting arrangements in place prior to a final YEC "go" decision to proceed with a capital project, the sale price estimate would be unlikely to be materially refined or "locked down" at the time the project is committed by YEC – and absent a firm or contingent negotiated sale price arrangement addressing the assumed future sale, YEC would bear all risks related to the sale price estimate.

The added complexity is the fact that due to fast-changing environmental regulations focused on net-zero electricity systems and other climate change initiatives, the diesel units purchased today based on an assumed future unconfirmed sale may be very difficult to market in future at any acceptable price [for example, change in minimum efficiency requirement]. The inability to sell those purchased diesel units in future would negatively impact efforts to reduce reliance on thermal generation.

Please also see the response to YUB-YEC-1-35 and YUB-YEC-1-36.

(b)

Paragraph 466 of Appendix A to Board Order 2018-10: Reasons for Decision regarding YEC's 2017/18 GRA references 20 MW diesel plant project at Takhini with an estimated capital cost at $62.2 million. This cost estimate was based on YEC's 2016 Resource Plan and estimated in 2016$.

The estimate in the 2016 Resource Plan was prepared by Stantec as Opinion of Probable Capital Cost (OPC) using Class 5 estimate. Stantec noted that "Class 5 estimates are prepared for any number of strategic business planning purposes…typical accuracy ranges for Class 5 estimates are - 20% to -50% on the low side, and +30% to +100% on the high side, depending on the technological complexity of the project, appropriate reference information, and the inclusion of an appropriate contingency determination. Given the expected level of effort for this study, an order of magnitude estimate of +50%/-30% is expected."

(c)

The BESS project preliminary capital cost estimate of $31.7 million in the Part 3 application was prepared by Hatch in 2020$, with +/- 30% accuracy using Class 4 estimate.

During the oral hearing, Ms. Zuliani, YEC Panel member from Hatch, stated the following regarding the BESS cost estimate [transcript page 353]:

> Class 4 estimate, which is where this project sits, is we've done a basic engineering phase, defined the project, and based our costs based on site specific considerations, benchmarks, and any other information, as we pointed out, based on past projects and discussions with vendors of major components.

REFERENCE: **Application, PDF page 92**

ISSUE: Diesel rental units

QUOTE: Due to fast-changing environmental regulations focused on net-zero electricity systems and other climate change initiatives, the diesel units purchased today based on an assumed future unconfirmed sale may be very difficult to market in future at any acceptable price.

QUESTION:

a) Is it the opinion of YEC that there will not be any requirements for firm capacity thermal generation in the future?

b) Please reconcile the above statement with YEC's forecast need of rental diesel generation units to at least 2035.

ANSWER:

(a) and (b)

No – YEC is not suggesting that there will not be any requirements for firm capacity thermal generation in the future. The referenced statement in the Application only highlights the potential issues and risks of securing "any acceptable price" related to any option that assumes diesel unit purchases today that rely for feasibility on assumed future sale of the purchased units. Appendix 3.1 specifically addresses issues defining an acceptable sale price for the financial feasibility of this "own/resale" option.

YEC will rely on firm thermal capacity in future years as illustrated in the response to YUB-YEC-1-1. However, YEC does not intend to sell the firm installed thermal units.

Please also see the response to YUB-YEC-1-35 (a) (b) and (c), YUB-YEC-1-37 (n), YUB-YEC-1-42 (a) and (d), and NY-YEC-1-20.

REFERENCE: **Application, PDF page 93**

ISSUE: Rented diesels

QUOTE: Dependable capacity shortfalls were forecast in the 2016 Integrated Resource Plan, based on expected future non-industrial peak load growth and the need to replace aging diesel infrastructure. After considerable planning and public review, and based on the Yukon Government's climate change objectives, the option of developing one new large diesel facility was discarded by YEC and replaced by YEC's 10-Year Renewable Electricity Plan (10-Year Plan) that includes new thermal replacements at YEC's different thermal facilities, the Atlin Hydro Expansion project EPA, the BESS project, dependable DSM capacity development, and the review of large renewable dependable capacity and energy options such as Tutshi-Moon Pumped Storage Hydro.

QUESTION:

a) Please provide a forecast in-service date for each of the following projects:
   i. The Atlin hydro expansion project EPA;
   ii. The BESS project; and
   iii. The Tutshi-Moon Pumped Storage project.

b) For the projects listed in part (a), please discuss the likelihood of delays and potential that the projects may not be completed before 2030.

c) For each of the projects listed in part (a), please describe the work completed to date and the hurdles to overcome with respect to those projects.

d) Please explain whether a large thermal facility produces more emissions than a configuration of rented diesel units of a similar size.

e) Do new diesel generating units produce less emissions than the diesel units that YEC rents on a per-MWh basis?

f) For each of the rented diesel units in YEC's forecast for 2023 and 2024, please provide the date that the rental unit was manufactured.

g) If YEC cannot produce the manufactured date, what is the average age of the rented diesel units?

h) For each of the projects listed in part (a), list the required stakeholders, their role, and the constituency they represent.

i) For each of the projects listed in part (a), please list each of the required approvals, both internal and external, for the project to proceed and the current status of each of those approvals.

j) What are the stop points for each project?

k) Are there any monetary thresholds that could represent a stop point for any of the projects? Please explain.

l) Please provide any and all letters of intent with respect to each of the listed projects.

ANSWER:

(a)-(c), (h)-(l)

YEC is not asking for decisions in this GRA regarding any of these projects as they are not expected to be in-service and useful during the test years. They have appropriately not been included in revenue requirement calculations. Requested information is provided separately below for each project.

Atlin Hydro Expansion Project EPA

The Atlin Hydro Expansion Project is ready to advance to construction upon receipt of permits and grant funding. Construction permits are expected by the end of 2023 and Tlingit Homeland Energy LP (THELP) continues to work with provincial, territorial and federal government departments and agencies to secure the funds necessary to advance the project. Should permits and funding be secured by spring 2024, THELP anticipates

being able to begin construction of the project in summer 2024 and an in-service date of late 2026/early 2027. Delays in receiving permits or funding would cause delays to the start of construction and subsequently, the project's in-service date.

The Atlin Hydro Expansion Project requires permits and grant funding to begin construction. Upon receipt of these items, THELP has indicated that the project can be completed in three construction seasons. To mitigate risks of delays during construction, THELP has undertaken a substantial geotechnical investigatory program for the project, invested significant time in project design and negotiated date-certain Engineer-Procure-Construct (EPC) contracts for key components of the project.

To date, THELP has completed most of the work required in the development phase of the project to make the project "shovel-ready" for construction upon receipt of permits (currently anticipated by the end of 2023) and additional project funding. This work has included project design, geotechnical investigations, archaeology and environmental studies/approvals, site survey, stakeholder and community consultation and engagement, submission of permitting applications, and acquisition of some financial backing in the form of both debt and grants from various government agencies (provincial, territorial and federal). The hurdles overcome since the project's conception include evolvement of the owner's (i.e., THELP's) representatives, review and optimization of the project's design, regulatory delays, cost escalation, and foreign exchange increases.

The stakeholders of the Atlin EPA project include:

- The Taku River Tlingit First Nation as the project owner and proponent. THELP is an entity owned by the First Nation.

- Government of Canada as a funder through various programs and a regulator through Department of Fisheries and Oceans.

- Canadian Infrastructure Bank as a project debt financer.

- BC Government as a funder and regulator via Ministry of Forests, Lands, Natural Resources and Operations & Ministry of Transportation and Infrastructure.

- Carcross/Tagish First Nation as a Yukon First Nation whose traditional territory the project overlaps.

- Yukon Government as a funder and regulator for parts of the project that are located in the Yukon.

- Yukon Energy Corporation as the Buyer of the electrical capacity and energy generated by the project.

Required British Columbia government, federal government and First Nation approvals and the status of these approvals is included in YUB-YEC-1-44 Attachment 1. YESAB assessment and Yukon government decision document approval for the project have been completed for the project's new transmission and substation facilities in Yukon, and Yukon OIC 2023-143 has prescribed this project as an excluded undertaking under the *Public Utilities Act*. The Atlin EPA also requires the EPA which has been executed between Yukon Energy and THELP and reviewed by the YUB in its report to the Minister (please see response to YUB-YEC-1-45 for status of conditions precedent provisions).

Transitioning the project from development to construction is the major stop point. Before construction can begin, THELP requires receipt of the regulatory permits needed for construction and the remainder of project financing to be secured in terms of both debt and grants. The Atlin Hydro Expansion project requires government funding to proceed with construction. Once funding has been received, THELP has structured its Engineer-Procure-Construct (EPC) contracts to mitigate foreseeable risks during construction (e.g., scope-creep and cost overruns), and included approximately 15% in contingency as part of the total project cost.

No Letters of Intent have been issued. Instead, THELP took the approach of involving contractors during the early stages of project design and budgeting. Through this process, three major contractors were identified to support the majority of the project's design and construction scope (Dent for civil work and substation construction, Midlite for transmission line construction, and Global Hydro for the supply, delivery and install of the hydro generator and turbine). The three contractors remain involved and committed to project completion and an open-book, defined-markup pricing structure.

BESS

The estimated completion date for the Battery Energy Storage System Project (BESS) project is Q3, 2024. The status of work completed to date is:

- Detailed design (50% complete).

- Foundation work (75% complete).
- Container manufacturing (40% complete).

The Battery Energy Storage System (BESS) project experienced significant delays, primarily due to a confluence of factors that extended beyond the initial timelines. A key reason for the postponement was the prolonged process in finalizing the terms and conditions following the contract award signing with the Engineering, Procurement, and Construction (EPC) contractor. This delay was further exacerbated by supply chain disruptions and a rapid escalation in material costs, a consequence of post-COVID inflationary pressures. These economic changes significantly impacted the cost structure of the project, leading to increased expenses for raw materials and subcontracting services. To address these unforeseen challenges, a change order was issued to extend the contract duration. This revision was necessary to accommodate the additional time needed to navigate the complex landscape of increased costs and supply chain hurdles, ensuring that the project could proceed despite the existing challenges faced by the main EPC contractor. The cumulative effect of these factors played a pivotal role in pushing the project's completion timeline beyond its original schedule.

The stakeholders include:

- YEC.
- First Nation Governments and development corporations: YEC has entered into agreements with Ta'an Kwach'an Council (TKC) and Chu Níikwän Limited Partnership (CNLP), by its general partner, Chu Níikwän Development Corporation, a Limited Partnership wholly owned by Kwanlin Dün First Nation (KDFN) as it relates to the Battery Energy Storage System Project (BESS). These agreements provide TKC and CNLP support of the BESS Project and Whitehorse Interconnection Project, and for YEC to provide project benefits to the TKC and CNLP.
- Yukon Government.
- Yukon residents.

The project approvals include:

- YEC Board of Directors approval of Stagegate 1-4 (complete).
- Land use permit (complete).
- Building permit (complete).

- Development permit (complete).
- YESAB project approval (complete).
- YUB Part 3 Application (complete).
- NAVCAN & Transport Canada assessments (complete).
- First Nations investment agreements (complete).
- Yukon Government Department of Justice approval (complete).

Tutshi-Moon Pumped Storage Project

YEC does not have a level of support from First Nation communities to advance early work on this project with confidence that the human and financial resources will be prudent. Therefore, currently, no further work is expected regarding this specific project.

(d) and (e)

When discussing emissions from a large thermal facility versus a configuration of rented diesel units of a similar size, several factors come into play:

Efficiency of Scale: Large thermal power plants often benefit from economies of scale, meaning they can produce energy more efficiently than smaller units when demands for thermal generation are high. Larger plants typically incorporate more advanced technology to optimize fuel use and reduce waste. This efficiency can result in lower emissions per unit of energy produced.

Emissions Control Technology: The emissions from any new facility with an operating capacity of more than a few megawatts using newly purchased permanent generators would be lower than those of a similarly sized facility consisting of rental units. The reason is that Yukon Energy has committed to the adoption of the best available emissions control technology for any new permanent diesel generators purchases. Currently the emissions bar is set by the EPA Tier 4 emissions standard. Rental diesel generators by nature are made to be mobile and easily deployed in relatively tight spaces. These benefits come with a tradeoff as regards emissions control. The rental units have emissions that meet the EPA Tier 2 standard but cannot be practically configured to meet the EPA Tier 4 standard. As such, any facility with newly purchased permanent diesel units would outperform a similarly sized facility with rental units**.**

Age and Maintenance of Equipment: The emissions from diesel units also depend on the age and maintenance of the equipment. Newer and well-maintained units tend to be more efficient and have better control systems for emissions compared to older or poorly maintained ones.

Operating Conditions: The actual load under which the diesel units are operating can also affect emissions. If the units are not operating at within their optimal range, they can be less efficient and produce more emissions per unit of energy produced than units that are operating within their optimal range.

Heat Recovery and Use: Large thermal plants often have the capability to recover waste heat for other purposes, such as district heating, which can make them more efficient overall. Small diesel units typically do not have this capability, which could mean that more energy is wasted as heat, leading to higher overall emissions for the same amount of electrical energy produced.

Given these points, a large thermal facility, despite its potential for high emissions, might still be more efficient and have lower emissions per unit of energy produced than an equivalent configuration of smaller rented diesel units, especially if it utilizes modern technology and complies with strict environmental regulations. However, this is a general assessment and a detailed life cycle analysis, and direct measurement would be necessary to make a definitive comparison for a specific case.

(f) and (g)

The units rented from year to year can change. YEC provides the required specifications, however, the actual unit delivered is decided upon by the vendor. Therefore, YEC is not able to provide the manufacture date or the average age of the incoming diesel rental units.

Summary of Non-provincial Authorizations

AGENCY	NATURE OF AUTHORIZATION/ APPROVAL	STATUS	COMMENTS	CONTACT
DFO	FAA for a HADD (Section 35 *Fisheries Act*)	Submitted Nov. 9, 2022 Agency review underway	FAA is under DFO review. The Proponent met with Katherine Znotinas and Dan Sneep, DFO, on August 7, 2020, to discuss application and were advised to apply directly for the FAA rather than requesting a review. Subsequent meetings with Katherine Znotinas have been conducted, including a site visit on September 8, 2021, and virtual meetings to discuss design changes. FAA review is still underway.	Katherine Znotinas, Biologist, Fish and Fish Habitat Protection Program Ecosystems Management Branch Fisheries and Oceans Canada/ Government of Canada Katherine.Znotinas@dfo-mpo.gc.ca
TRTFN	Project Approval	Ongoing engagement.	TRTFN Clan Directive supports the Project subject to successful permitting approval. TRTFN is part of the CEDP review and comment process. Draft Recommendation Report has been developed by the TRTFN Review group for FN comment/approval.	Carter Leuschen Lands Engagement Officer Taku River Tlingit First Nation lands.engagement@gov.trtfn.com
Transport Canada, NPP	NPP authorization for Water Control Structure	Submitted Feb. 2023. Issued July 11, 2023	File No. 2005-500184 (Surprise Lake) and 2023-508961 (Pine Creek)	Lawrence Kuan Navigation Protection Program Programs Group Transport Canada, Pacific Region lawrence.kuan@tc.gc.ca
Natural Resources Canada	Explosives Regulation Authorization	To be submitted	For storage of explosives to be used during construction blasting	TBC
Yukon Highways and Public Works	Work Within the RoW (Geotechnical)	Permit received	Permit for geotechnical investigations on Yukon side (8 boreholes).	Wendy Holway Junior Maintenance Technician Transportation Maintenance Branch, Operational Support Unit Wendy.holway@yukon.ca

AGENCY	NATURE OF AUTHORIZATION/ APPROVAL	STATUS	COMMENTS	CONTACT
Yukon Land Management Branch	Land Use Permit (Transmission Line clearing/construction)	Submitted, YESAB Decision Document issued July 2023, permit pending updated design.	For transmission line clearing/construction/ operation. Included as part of 2020 YESAB submission (Decision Document issued), but requires regulatory review of updated transmission line design to issue permit.	Graeme Poile Land Use Officer Energy, Mines & Resources Land Management Branch 867-667-5232 Graeme.Poile@yukon.ca
Yukon Highways and Public Works	Work Within the Right of Way	Submitted, permit pending updated design.	Included as part of 2020 YESAB submission (Decision Document issued), but requires regulatory review of updated transmission line design to issue permit.	Wendy Holway Junior Maintenance Technician Transportation Maintenance Branch, Operational Support Unit Wendy.holway@yukon.ca
Yukon Highways and Public Works	Access Permit (Transmission Line)	To be submitted with updated design.	Access included as part of 2020 YESAB submission (Decision Document issued), but individual permits to be submitted directly to HPW based on updated transmission line design.	Wendy Holway Junior Maintenance Technician Transportation Maintenance Branch, Operational Support Unit Wendy.holway@yukon.ca
Yukon Forest Management Branch	Forest Resources Permit	Not submitted	Confirmation received that this permit (permission to cut trees) is only required if not covered by Land Use Permit or Work Within the RoW.	TBC
Yukon Land Management Branch	License of Occupation (Transmission Line)	To be submitted	Replaces Land Use Permit with final surveyed license for long term operations. Typically issued for 10 years and will require renewal throughout life of Project.	Graeme Poile Land Use Officer Energy, Mines & Resources Land Management Branch 867-667-5232 Graeme.Poile@yukon.ca
Yukon Land Management Branch	Land Use Permit (Substation)	Submitted July 2022, review pending under ATCO YESAB Package (2022-0117)	For substation clearing/construction. Part of the YESAB submission by ATCO (2022-0117). YESAB Evaluation in progress.	Permit pending through ATCO. Anthony Wachtler Project Manager Electricity, ATCO 780-220-5397 anthony.wachtler@atco.com

AGENCY	NATURE OF AUTHORIZATION/ APPROVAL	STATUS	COMMENTS	CONTACT
Yukon Highways and Public Works	Access Permit (Substation)	To be submitted	Access included in the YESAB submission by ATCO (2022-0117), but individual permits to be submitted directly to HPW.	Wendy Holway Junior Maintenance Technician Transportation Maintenance Branch, Operational Support Unit Wendy.holway@yukon.ca
Yukon Land Management Branch	Commercial Land Lease (Substation)	Submitted July 2022, review pending under ATCO YESAB Package (2022-0117)	For substation lease during operations. Part of the YESAB submission by ATCO (2022-0117). YESAB Evaluation in progress.	Permit pending through ATCO. Anthony Wachtler Project Manager Electricity, ATCO 780-220-5397 anthony.wachtler@atco.com

Summary of Provincial Authorizations

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Conditional Water Licence (THEL)	*Water Sustainability Act*	Diversion of flows, new works	Pending	APL Water Licence Amendment Application & CEDP Submission	2.5.2 Project Construction (2.5.2.4, 2.5.2.5, 2.5.3.1, 2.5.3.2) 4.3.1 Hydrology & Hydrogeology 5.5 Water Rights, Appendix 6
Conditional Water Licence (APL)		Additional Surprise Lake storage	Pending		
Conditional Water Licence Amendment (APL)		Modifications to licenced works	Pending		
Permit Over Crown Land	*Water Sustainability Act*	Surprise Lake inundation	Pending	CEDP Submission	4.3.1 Hydrology & Hydrogeology (4.3.1.5, Storage & Surprise Lake Inundation)
General Area Licence of Occupation	*Land Act*	Project footprint including affiliated construction areas	Pending	Submission of shapefiles for Project area and CEDP submission	Project Maps show work areas & land use within the GALOO – see Appendix 7 & 8
Licence of Occupation	*Land Act*	Applications for borrow sites at Otter Creek and near the Atlin Airport	Pending	Submission of shapefiles for borrow areas.	2.1.3.7 Borrow, Spoil Sites and Staging/Laydown
Crown Land Lease Amendment (APL)	*Land Act*	Amendment to lease parcels 6408250 and 6408670	Pending	CEDP as supporting information. Amendment to APL Leases to update associated Management Plan.	2.1.2.2 Legal Description of Project Area 2.4 Description of Land Requirements 5.2.2 Land Use 5.3 Implications for Adjacent or overlapping Crown Land Tenure (5.3.4.2, LUT-8)
Recreation Site Authorization	*Forest Act*		Not applicable	No physical project overlap with recreation sites.	

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Mines Act Permits	*Mines Act*	Permits for borrow sites at Otter Creek	Pending	Notice of work application packages	2.1.3.7 Borrow, Spoil Sites and Staging /Laydown 4.5 Summary of Environmental Effects, Mitigation and Significance 5.7 Summary of Socio-Economic Effects, Mitigation and Significance 7.5 Summary of Potential Project Effects on First Nations Interests
Notifications	*Water Sustainability Act*	In water and near water Project works for generation infrastructure	Pending	CEDP Submission	2.2.1 Regional Overview 2.5 Project Activities 2.5.2.1 Access Management and Road Construction 2.5.2.3 Site Preparation 2.5.2.5 Penstock (General Penstock Construction Methods, Minor Water Crossings, Spruce Creek & Wye Branch) 2.5.2.7 Transmission Line 2.5.2.8 Commissioning 2.5.2.11 Construction Schedule 2.5.3 Operations and Maintenance 2.5.3.2 Project Operations (Ramping) Appendix 5 – CEMP

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Change Approvals	*Water Sustainability Act*	In water and near water Project works for generation infrastructure	Pending	CEDP Submission	2.2.1 Regional Overview 2.5 Project Activities 2.5.2.4 Surprise Lake Control Structure 2.5.2.5 Penstock (General Penstock Construction Methods & Watercourse Crossings) 2.5.2.6 Powerplant (Tailrace) 2.5.2.11 Construction Schedule 4.1.1.4 Fish and Fish Habitat Effects Assessment 4.1.2.4 Amphibians Effects Assessment 4.1.3.4 Water Quality Effects Assessment (WQ-2) Appendix 5 – CEMP
Notifications	*Water Sustainability Act*	In water and near water Project works for transmission line	To be submitted	Detailed design and access plan	
Change Approvals	*Water Sustainability Act*	In water and near water Project works for transmission line	TBD	Not anticipated to be required at this time, however pending confirmation via detailed design and access plan	
Investigative Licence	*Land Act*	Permits investigative work	Issued July 2022	Licence No. SK925483, expiry July 2023, as per modification Agreement dated July 13, 2022. Extension granted September 6, 2023 to extend to	N/A (supporting information available as a separate application)

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Occupant Licence to Cut	*Forest Act*	Allows land tenure holder to clear trees	Issued May 2023	FRPA s.52 Exemption (instead of OLTC) issued to Tlingit Homeland Energy Ltd. May 10, 2023. Extension granted to August 29, 2028.	N/A (supporting information available as a separate application)
Highway Use – Exploratory	*Transportation Act*	Permits investigative work	Issued April 2023	Permit 2022-03393 issued April 5, 2023, expiry September 30, 2023.expiry August 28, 2023. Extension granted to Sept. 30, 2024.	N/A (supporting information to be provided as a separate application)
Permission to Construct, Use and Maintain Access to a Highway	*Transportation Act*	Permission for development of new and use of existing access points on to MOTI roads.	To be Submitted	Identify and apply for access roads intersecting main roads (penstock and power plant access roads, transmission line access from Surprise Lake Road and Atlin Highway).	N/A (supporting information to be provided as a separate application)
Permission to Construct Works (Utilities) on a Highway	*Transportation Act*	Permission to construction utilities (penstock, powerline) in the right-of-way	To be Submitted	Identify and apply for Surprise Lake Road bridge upgrades; penstock crossing at Surprise Lake Road, Spruce Creek Road and Warm Bay Road; transmission line along Atlin Highway.	N/A (supporting information to be provided as a separate application)
Overload Permit (MOTI)	*Transportation Act*	For owner-supplied materials coming to site	To be submitted if required	Identify weight and size limits for vehicles on Project-area roads and construction transport needs; apply online for relevant term or single trip permits as required.	

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Oversize Permit (MOTI)	*Transportation Act*	For owner-supplied materials coming to site	To be submitted if required	Identify weight and size limits for vehicles on Project-area roads and construction transport needs; apply online for relevant term or single trip permits as required.	
Special Use Permit	*Forest Act*	Permit industrial use of FSRs within the Project area	To be submitted	Identification of all roads for access to Project areas that are FSRs. Obtain Third Party Road Use Agreements for any roads that have SUPs in place currently.	N/A (supporting information to be provided as a separate application)
Road Permit – Forestry	*Forest Act*	A road permit (RP) is issued in accordance with Part 8 of the FA and authorizes the holder to construct, use and maintain a forest road.	To be submitted, if required	Identification of FSRs requiring upgrade to accommodate construction use, if any.	N/A
Junction Permit – Forestry	*Forest Act*	Permission for creation of any new junction with a FSR.	To be submitted, if required	Identification of FSRs requiring intersection with new roads, if any.	N/A
Camp Temporary Water Use Approval	*Water Sustainability Act*	Groundwater for use in a camp will require a license to be issued under the WSA (section 8).	To be submitted	Well system must be designed and constructed per the specifications of the Groundwater Protection Regulation (GWPR) under the Water Sustainability Act and approved under the act for water withdrawal. .	N/A
Camp Municipal Sewage Registration	*Environmental Management Act (Municipal Wastewater Regulation)*	Registration required for a camp with a design flow rate of 2.27 m^3/day or greater (typically more than 100 persons)	To be submitted	Design of the sewage system.	N/A

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Water System Construction Permit	*Drinking Water Protection Act (Northern Health)*	Anyone building a water system requires construction approval from a public health engineer.	To be submitted	Design of the drinking water system.	N/A
Water System Operation Permit	*Drinking Water Protection Act (Northern Health)*	Anyone who operates a water supply system which provides water for domestic purposes requires a valid water supply operating permit.	To be submitted		N/A
Food Services	*Public Health Act (Northern Health)*	Approval for camp kitchen use and food provision	To be submitted		N/A
Municipal Wastewater Registration	*Public Health Act (Northern Health)*	Before the construction, alteration, or repair of a sewerage system, an Authorized Person must submit information respecting the designed details of the system on a Record of Sewerage System form.	To be submitted	Design of sewerage system and letter of certification	N/A
Authorization for Alteration of a Dam	*Dam Safety Act*	An alteration or improvement to or replacement of all or part of a dam must be authorized under the Act by an authorization, change approval or order. An owner of a dam must, within 30 days after completion of an alteration or improvement to or replacement of all or part of the dam, submit to a dam safety officer (a) a written report on the work and the manner in which the alteration, improvement or replacement was performed, and (b)a copy of the as-built drawings.	To be submitted	Compilation of the requested information (primarily from CEDP & design) as well as future plans that are pending development such as the Draft Operation Maintenance and Surveillance Manual, and Draft Dam Emergency Plan.	2.1.3.1 Surprise Lake Control Structure 2.5.2.4 Surprise Lake Control Structure Construction

AUTHORIZATION REQUIRED	STATUTE/ REGULATION	DESCRIPTION	STATUS	PREREQUISITES	DEVELOPMENT PLAN REFERENCE
Borrow location(s) Temporary Water Use Approval	*Water Sustainability Act*	For batch plant, dust suppression, fire standby, etc., require use approval (Section 8) for short term use.	To be submitted	.	N/A
Concrete Code of Practice Registration	*Environmental Management Act*	Waste discharge for concrete and concrete by-products	To be submitted (if required)	Any new establishments must register and comply with the code in order to be authorized in order to discharge waste.	N/A
Burn Registration Number	*Wildfire Act/Wildfire Regulation*	Burn Registration number as per the BC Wildfire Act/Reg if burning activities fall under Category 3	To be submitted	Required for activities that fall under Category 3 (Open Fires)	N/A
Wildfire Exemption	*Wildfire Act/Wildfire Regulation*	Exemption from Section 6(3)a of the Wildfire Regulation	Issued June 2023 Future applications to be submitted, if required	Identified work that poses a fire risk during periods of restrictions.	N/A
Effluent Discharge Authorization	*Environmental Management Act*	Required for any substance to be discharged which does not fall under batch plant or sewage permit	To be submitted, if required	Not anticipated at this time, however should methods change as construction methods are confirmed, this may be necessary.	N/A
Logging Near Energized Lines	*BC Hydro*	A tree growing within Limits of Approach (3 m of the BC Hydro line) must be removed it can only be taken down under the supervision of a certified utility arborist.	BC Hydro to be contacted as required.	Detailed clearing plan.	N/A

REFERENCE: **Application, PDF page 93**

ISSUE: Ongoing YEC dependable capacity planning

QUOTE: … the Atlin Hydro Expansion EPA (amendments to the EPA have extended condition precedent timelines to October 31, 2023 to facilitate funding discussions) …

QUESTION:

a) Please provide the amended EPA with revised costs and details on what was provided to remove each of the conditions precedent.

ANSWER:

(a)

The Atlin Hydro Expansion EPA has been amended to extend condition precedent timelines to June 30, 2024. Please see YUB-YEC-1-45 Attachment 1.

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#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

October 17, 2023

Tlingit Homeland Energy Limited Partnership
By Its General Partner
Tlingit Homeland Energy Limited
P.O. Box 408
Atlin, BC, V0W 1A0

Re: Electricity Purchase Agreement Dated January 14, 2022 as amended and restated on April 12, 2022 and amended on September 30, 2022 and May 8, 2023 (collectively, the "EPA") Between Yukon Energy Corporation ("YEC") and Tlingit Homeland Energy Limited Partnership By Its General Partner Tlingit Homeland Energy Limited ("THELP")

YEC is writing to confirm its agreement with THELP that the dates contained in the EPA for satisfaction of the conditions precedent in Sections 2.1(d)(i),(ii),(iii),(iv),(v),(vi),(vii),(viii) and (ix) are extended from their current dates until the dates set out below. Capitalized terms used and not defined in this letter have the meanings in the EPA.

	CONDITION	Updated Due Date
1.	2.1(d)(i) Parties and AEY enter into an Interconnection Agreement	**June 30, 2024**
2.	2.1(d)(ii) Parties and AEY agree on budgeted costs for AEY System Upgrades	**June 30, 2024**
3.	2.1(d)(iii) for Seller to submit Funding Plan to Buyer	**June 30, 2024**
4.	2.1(d)(iii) for Buyer to give Notice to Seller that Buyer is satisfied with Funding Plan	**June 30, 2024**
5.	2.1(d)(iv) for Seller to receive Clean Energy Development Plan authorizations for Seller's Plant located in British Columbia and the YESAA Decision Documents for the Seller's Plant located in the Yukon Territory, on terms and conditions satisfactory to each of the Parties, acting reasonably	**June 30, 2024**
6.	2.1(d)(v) Buyer receives approvals of the EPA from Governmental Authorities on terms and conditions satisfactory to the Parties, acting reasonably	**June 30, 2024**
7.	2.1(d)(vi) Seller will have sought and obtained approval of the EPA by the Taku River Tlingit First Nation by way of Clan Directive or a Joint Clan Meeting Mandate, on terms and conditions satisfactory to the Parties, acting reasonably	**June 30, 2024**
8.	2.1(d)(vii) Seller will have sought and obtained such consents as may be required from each of BC Hydro and The Canada Life Assurance Company of Canada to enter into the EPA, such consents to be on terms and conditions satisfactory to each of the Parties, acting reasonably;	**June 30, 2024**
9.	2.1(d)(viii) Parties will have agreed, acting reasonably, upon an allocation of the Environmental Attributes under this EPA based upon the requirements of the funding contributed to Seller's Plant by the governments of the Yukon Territory, British Columbia, and Canada	**June 30, 2024**
10.	2.1(d)(ix) YEC will have entered into an implementation agreement with AEY for implementation of the EPA	**June 30, 2024**

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Except for this letter and the previous conditions precedent extensions on February 24, 2022, March 31, 2022, May 25, 2022, July 25, 2022, August 31, 2022, September 30, 2022, January 31, 2023, and April 26, 2023 the EPA remains in full force and effect, unamended.

Yukon Energy Corporation

Per:

Agreed on October 17, 2023

Tlingit Homeland Energy Limited Partnership
By Its General Partner
Tlingit Homeland Energy Limited

Per:

DocuSigned by:
Lee Francoeur
E0E5BB7477474DF...

REFERENCE: **Application, PDF pages 94-95**

ISSUE: Ongoing YEC dependable capacity planning

QUOTE: YEC is currently completing a review and update of the 10-Year Renewable Electricity Plan to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro project. Sensitivities will examine options to address those delays as well as options to address higher-than-expected growth in peak demand over the next decade.

In the longer-term context, YEC will continue to evaluate the relative cost of diesel rentals versus purchase of new thermal capacity taking into account options to sell purchased new diesels when they are no longer required on a long-term basis, e.g., when new dependable capacity is added to the grid as a result of the development of the Tutshi-Moon Pumped Storage Hydro project. However, based on currently available information, there are significant potential risks involved in purchasing versus renting diesels for capacity that is no longer expected to be needed after 10 years of operation:

QUESTION:

a) Since YEC is expecting delays with respect to the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro project and is forecasting continued load growth, how valid is the statement “based on currently available information, there are significant potential risks involved in purchasing versus renting diesels for capacity that is no longer expected to be needed after 10 years of operation”? Please explain.

b) Please explain why it has taken at least seven years for YEC to determine that: “In the longer-term context, YEC will continue to evaluate the relative cost of diesel rentals versus purchase of new thermal capacity taking into account options to sell purchased new diesels when they are no longer required on a long-term basis”.

c) Please provide a complete list of all parties that have expressed an interest in the Tutshi-Moon Pumped Storage Hydro or Moon Lake Pump Storage Phase 1 and

Phase 2. Please identify all necessary consents and approvals that are required for the project to be viable to proceed.

ANSWER:

(a)

The statement is valid; there are significant potential risks.

Following from the quote a specific example is provided of risks in securing an acceptable price that would clearly show that "own/resale" is less costly to ratepayers than diesel rentals when assessing a capacity that is not expected to be needed after 10 years of operation. Please also see response to YUB-YEC-1-35(a-d).

Forecasting prices is challenging for one year ahead; forecasting prices for ten years in the future results in significantly less certainty on the amounts, thereby creating more risk. Securing vendor commitments to repurchasing the units is constrained by uncertainty on timing for any sale and related inability to provide a price applicable to any such sale.

Appendix 3.1 of the Application confirms for the current GRA test years that no feasible option exists for the diesels that are being rented. Appendix 3.1 also notes that the 10 Year Renewable Electricity plan is currently being reviewed and updated to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the Tutshi-Moon Pumped Storage Hydro Project.

(b)

This assertion that it has "taken at least seven years" is not correct; YEC has analyzed this repeatedly and it is ongoing. YEC's comment even states "YEC will continue to evaluate" as opposed to "start to evaluate".

(c)

Based on feedback from the 10-Year Renewable Plan, YEC is aware that the following groups were interested in the project:

- Tour operators;

- Outfitters;
- Yukon Conservation Society;
- Yukon citizens;
- Low Carbon Yukon Stakeholder Committee;
- Yukon Utilities Consumer Group;
- First Nations.

The feedback informed numerous consents and approvals that would be required, including, but not limited to:

- Environmental and other regulator approvals in both British Columbia and (for required new transmission) Yukon, as well as DFO for fisheries and fish habitat impacts/ permits

- First Nation government support and agreements for project effects on traditional and / or asserted territories in the Yukon; and

- Significant federal, Yukon and British Columbia funding approvals in order to make the project economical for ratepayers.

REFERENCE: **Application, PDF page 95**

ISSUE: Diesel rentals

QUOTE: In the longer-term context, YEC will continue to evaluate the relative cost of diesel rentals versus purchase of new thermal capacity taking into account options to sell purchased new diesels when they are no longer required on a long-term basis, e.g., when new dependable capacity is added to the grid as a result of the development of the Tutshi-Moon Pumped Storage Hydro project. However, based on currently available information, there are significant potential risks involved in purchasing versus renting diesels for capacity that is no longer expected to be needed after 10 years of operation…

QUESTION:

a) As YEC is currently into its seventh year of rented diesels, please explain why YEC delayed consideration of the longer term context.

ANSWER:

(a)

The questions' premise is not correct - YEC never delayed consideration of the longer-term context.

Throughout the referenced period, YEC resource planning continued to consider, on an ongoing basis, the longer-term 10–20-year context for requirements, options and proposed plans to address N-1 dependable capacity shortfalls on the YIS and provide optimal long run generation resources for the YIS.

Rental diesels were projected in the 10-Year Renewable Electricity Plan (published in 2020) to be required only until other permanent capacity resources could be in-service. This included phase 1 of the proposed Tutshi-Moon Pumped Storage Hydro project planned to be in-service before 2030. The 10-Year Renewable Electricity Plan is currently

being reviewed and updated to take into account ongoing changes, including delays expected in development of the Atlin Hydro Expansion EPA and the fact the YEC does not have full support from First Nation communities to advance the Tutshi-Moon Pumped Storage Project at this time.

REFERENCE: **Application, PDF page 95**

ISSUE: Rented diesels

QUOTE: As noted above, the LCOC for Faro rented diesels over a 10-year period with 4% annual price inflation equals $239/kW-yr.

In contrast, using new purchase costs for the 5 MW of Faro units in service in 2024 at $3.66 million/MW, the LCOC for new units sold in the 11th year after commissioning can only compete with the rental option at unrealistically high sales prices. For example, an unrealistic 10-year sales price equal to 75% of original cost (reflecting the remaining three-quarters of the original expected life) yields an LCOC for the purchase option of $278/kW-yr which remains much higher than the LCOC for the rental option in these specific circumstances.

QUESTION:

a) Please provide an Excel spreadsheet, with formulae intact, showing the revenue requirement costs for 5 MW Faro units on an annual basis for years 1 to 15, with separate columns for: undepreciated capital at the beginning of the year, return, depreciation, undepreciated capital cost at the end of the year, maintenance costs, and any other cost information shown separately and deemed relevant. Do not include capital costs for system upgrades to connect the Faro units.

b) Please provide a separate Excel spreadsheet, with formulae intact, showing the revenue requirement costs on an annual basis for years 1 to 15 for the rental of 5 MW (three rental units) of generation capacity, with separate columns for: rental costs, cost of running the units ahead of lower cost generation sources, annual delivery and removal costs of the units, annual connection and disconnection costs of the units, maintenance costs, and any other cost information deemed relevant shown separately. Do not include capital costs for system upgrades to connect the rented diesel units.

c) Please provide the capital expenditure for the purchase of the 5 MW diesel unit at Faro.

d) Please provide the detailed economic analysis in spreadsheet format for the following: "… using new purchase costs for the 5 MW of Faro units in service in 2024 at $3.66 million/MW, the LCOC for new units sold in the eleventh year after commissioning can only compete with the rental option at unrealistically high sales prices. For example, an unrealistic 10-year sales price equal to 75 percent of original cost (reflecting the remaining three-quarters of the original expected life) yields an LCOC for the purchase option of $278/kW-yr which remains much higher than the LCOC for the rental option in these specific circumstances."

e) Please provide a table individually listing all thermal units utilized by YEC, separating the rental units from YEC-owned units. For each of the units, provide the actual generation in kWh, the efficiency, hours of operation, generation required for maintenance runs, fuel consumed per unit, and all-in costs to operate by month and by year for the years 2021 and 2022.

f) For the diesel rental units, please explain which party bears the risks if the units fail to operate as planned.

ANSWER:

(a) and (b)

Please see YUB-YEC-1-48 Attachment 1 for the requested information in MS excel format.

(c)

The total added capacity for the Faro diesel replacement project is 5 MW, two 2.5 MW EPA Tier 4 modular diesel units, expected to be available for the 2024/25 winter to displace diesel rentals.

The total forecast cost of $18.2 million includes $15.2 million EPC contractor cost and about $3 million other costs as detailed in Table 5.1A-1.1 in Tab 5.

Item Description	Amount
EPC Contractor – Faro	15,180,000
Faro share of Thermal Replacement Project non-EPC Contractor costs for Faro, Whitehorse and Dawson estimated at approximately 30.3% of $9.885 million (includes Station Service Supply ($0.45 million), YEC internal cost ($1.185 million), Owner's Engineer (BBA at $0.655 million), Assessment and Permitting ($0.29 million), Engagement ($0.28 million), Fuel for on-site commissioning ($0.89 million), Contingency ($2.379 million), AFUDC ($1.71 million), feasibility and engineering ($0.162 million), initial planning costs ($1.884 million).	2,995,000
Total Budget	**18,175,000**

(d)

Please see YUB-YEC-1-48 Attachment 2 for the requested information in MS excel format.

The calculated LCOC of $281/kW-yr revises the $278/kW-yr provided in the Application, showing LCOC ratepayer cost for 10 years use – the analysis assumes that the unit is then sold at sales price equal to 75% of the original cost, i.e., the price needed to clear the year-end undepreciated balance after 10 years as shown in Attachment 2. The LCOC will increase if a lower sale price occur, and decrease if a higher sale price occurs.

Based on the excel analysis assumptions in YUB-YEC-1-48 Attachment 1 for rental diesels, the 10 year LCOC for rentals is approximately $239/kW-yr (as compared to approximately $250/kW-yr for 15 years).

(e)

Please see YUB-YEC-1-48 Attachment 3 which shows the list of thermal units with monthly generation numbers and hours of operation for 2021 and 2022. YEC does not separately record diesel fuel liters used by individual rental units, therefore, the liters are estimated based on total diesel fuel usage and provided in the response to YUB-YEC-1-1 (d).

YUB-YEC-1-48 Attachment 4 provides litres and efficiencies by month and by location for 2021 and 2022.

Please also see the response to YUB-YEC-1-24 (d) and (e).

(f)

YEC bears the risk of being required to find an alternative source of power with the loss of generation. However, the contractor bears the monetary risk of maintenance and repairs on the units that fail to operate as planned.

YEC 2023/24 GRA
YUB-YEC-1-48 Attachment 1

Faro Diesel Rental LCOC for 3 units 1.8 MW each

Winter MW		**5.40**	
O&M (Fixed) per MW	2024	220	$000/MW
O&M (Fixed)	2024	1,191	$000/yr
Life		**15**	years
Rental escalation		4.0%	per yr

Weighted Average Cost of Capital	**6.018%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.94%**
PV of 15 Year Cost at 2024$ ($000)	**15,664**
Project LCOC ($/MW)	**$249,944**

Year	Faro Diesel Rental LCOC			
	Year-End Balance $000	Depr $000	Return $000	O&M $000
2024				1,191
2025				1,238
2026				1,288
2027				1,339
2028				1,393
2029				1,448
2030				1,506
2031				1,567
2032				1,629
2033				1,695
2034				1,762
2035				1,833
2036				1,906
2037				1,982
2038				2,062
NPV				15,664

Year from In-service	Annual Winter Capacity MW, 5.4
1	5.40
2	5.40
3	5.40
4	5.40
5	5.40
6	5.40
7	5.40
8	5.40
9	5.40
10	5.40
11	5.40
12	5.40
13	5.40
14	5.40
15	5.40

Notes:

1. Diesel rental cost is based on forecast for 2024, includes equipment rental cost, transportation cost and commissioning cost.
2. Weighted average cost of capital is based on proposed ROE at 8.70% and new long term debt cost at 4.23%

YEC 2023/24 GRA
YUB-YEC-1-48 Attachment 1

Diesel Replacement Options - Faro 5 MW

Winter MW		**5.00**	
Capital ($000)	2024	**$18,175**	
Fixed O&M	2020	**$85**	$000/yr
Assumed Life		**40**	years

Weighted Average Cost of Capital	**6.018%**
Inflation Rate	**2%**
Real Weighted Average Cost of Capital	**3.94%**
PV of 15 Year Cost at 2024$ ($000)	**$15,184**
Project LCOC for 15 Years ($/MW) at 2024$	**$261,659**

Year	Diesel Replacement Options - Faro 5 MW				
	Year-End Balance $000	Depr $000	Return $000	Fixed O&M $000	Total $000
2024	17,721	454	1,080	92	1,626
2025	17,266	454	1,053	94	1,601
2026	16,812	454	1,025	96	1,576
2027	16,358	454	998	98	1,550
2028	15,903	454	971	100	1,525
2029	15,449	454	943	102	1,499
2030	14,994	454	916	104	1,474
2031	14,540	454	889	106	1,449
2032	14,086	454	861	108	1,424
2033	13,631	454	834	110	1,398
2034	13,177	454	807	112	1,373
2035	12,723	454	779	114	1,348
2036	12,268	454	752	117	1,323
2037	11,814	454	725	119	1,298
2038	11,359	454	697	121	1,273
NPV					15,184

Year from In-service	Annual Winter Capacity MW, 5
1	5.00
2	5.00
3	5.00
4	5.00
5	5.00
6	5.00
7	5.00
8	5.00
9	5.00
10	5.00
11	5.00
12	5.00
13	5.00
14	5.00
15	5.00

Notes:
1. Faro diesel replacement cost as per Table 5.1A-1.1 in Tab 5.
2. Weighted average cost of capital is based on proposed ROE at 8.70% and new long term debt cost at 4.23%

YEC 2023/24 GRA
YUB-YEC-1-48 Attachment 2

Diesel Replacement Options - Faro 5 MW

Winter MW		**5.00**	
Capital ($000)	2024	**$18,175**	
Fixed O&M	2020	**$85**	$000/yr
Assumed Life		**40**	years

Weighted Average Cost of Capital	6.018%
Inflation Rate	2%
Real Weighted Average Cost of Capital	3.94%
PV of 10 Year Cost at 2024$ ($000)	$11,884
Project LCOC for 10 Years ($/MW) at 2024$	$281,084

Year	Diesel Replacement Options - Faro 5 MW				
	Year-End Balance $000	Depr $000	Return $000	Fixed O&M $000	Total $000
2024	17,721	454	1,080	92	1,626
2025	17,266	454	1,053	94	1,601
2026	16,812	454	1,025	96	1,576
2027	16,358	454	998	98	1,550
2028	15,903	454	971	100	1,525
2029	15,449	454	943	102	1,499
2030	14,994	454	916	104	1,474
2031	14,540	454	889	106	1,449
2032	14,086	454	861	108	1,424
2033	13,631	454	834	110	1,398
NPV					11,884

Year from In-service	Annual Winter Capacity MW, 5
1	5.00
2	5.00
3	5.00
4	5.00
5	5.00
6	5.00
7	5.00
8	5.00
9	5.00
10	5.00

Notes:
1. Faro diesel replacement cost as per Table 5.1A-1.1 in Tab 5.
2. Weighted average cost of capital is based on proposed ROE at 8.70% and new long term debt cost at 4.23%.

YEC 2023/24 GRA
Jan-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	5.0	5.0	12.6	12.6
Dawson	Diesel	P158	DD2	21.5	21.5	30.6	30.6
Dawson	Diesel	P158	DD3	6.3	6.3	11.2	11.2
Dawson	Diesel	P158	DD4	31.0	31.0	37.0	37.0
Dawson	Diesel	P158	DD5	17.0	17.0	16.7	16.7
Dawson	Diesel	P158	YM1	2.1	2.1	1.4	1.4
		Total Dawson Diesel		**82.9**	**82.9**	**109.5**	**109.5**
Faro	Diesel	P131	FD1	1.9	1.9	1.0	1.0
Faro	Diesel	P131	FD7	4.2	4.2	2.0	2.0
Faro	Diesel	YM	YM20	1.3	1.3	1.8	1.8
Faro	Diesel	YM	YM21	44.6	44.6	25.7	25.7
Faro	Diesel	YM	YM22	0.2	0.2	0.5	0.5
Faro	Diesel	YM	YM23	45.2	45.2	26.1	26.1
Faro	Diesel	YM	YM24	0.0	0.0	1.2	1.2
Faro	Diesel	YM	YM25	46.4	46.4	26.6	26.6
Faro	Diesel	YM	YM26	0.2	0.2	0.3	0.3
		Total Faro Diesel		**143.9**	**143.9**	**85.2**	**85.2**
Mayo	Diesel	P116	MD1	0.7	0.7	1.2	1.2
Mayo	Diesel	P116	MD2	1.1	1.1	1.3	1.3
Mayo	Diesel	P116	MD3	0.6	0.6	1.1	1.1
		Total Mayo Diesel		**2.4**	**2.4**	**3.5**	**3.5**
Whitehorse	Diesel	P126	WD4	27.0	27.0	13.0	13.0
Whitehorse	Diesel	P126	WD5	22.7	22.7	11.0	11.0
Whitehorse	Diesel	P126	WD6	26.3	26.3	12.0	12.0
Whitehorse	Diesel	P126	WD7	12.6	12.6	5.7	5.7
Whitehorse	Diesel	YM	YM10	147.1	147.1	85.7	85.7
Whitehorse	Diesel	YM	YM11	165.1	165.1	149.5	149.5
Whitehorse	Diesel	YM	YM12	157.4	157.4	78.0	78.0
Whitehorse	Diesel	YM	YM13	147.8	147.8	111.7	111.7
Whitehorse	Diesel	YM	YM14	85.4	85.4	54.2	54.2
Whitehorse	Diesel	YM	YM15	125.5	125.5	74.9	74.9
Whitehorse	Diesel	YM	YM16	104.0	104.0	67.6	67.6
Whitehorse	Diesel	YM	YM17	86.2	86.2		
Whitehorse	Diesel	YM	YM18	24.4	24.4	54.0	54.0
Whitehorse	Diesel	YM	YM19	147.4	147.4	89.3	89.3
		Total Whitehorse Diesel		**1,278.9**	**1,278.9**	**806.6**	**806.6**
Whitehorse	LNG	WG0	WG1	0.0	0.0		
Whitehorse	LNG	WG0	WG2	1,896.7	1,896.7	461.0	461.0
Whitehorse	LNG	WG0	WG3	1,590.2	1,590.2	386.0	386.0
		Total Whitehorse LNG		**3,486.9**	**3,486.9**	**847.0**	**847.0**

		Total	Rental diesel
Whitehorse LNG		3,486.9	
Diesel		1,508.1	1,328.2
Whitehorse		1,278.9	1,190.3
Dawson		82.9	
Faro		143.9	137.9
Mayo		2.4	
Total thermal generation		4,995.0	1,328.2

YEC 2023/24 GRA
Feb-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	16.3	21.3	30.6	43.2
Dawson	Diesel	P158	DD2	36.3	57.7	50.1	80.7
Dawson	Diesel	P158	DD3	43.3	49.7	56.9	68.1
Dawson	Diesel	P158	DD4	53.2	84.3	59.9	96.9
Dawson	Diesel	P158	DD5	57.0	74.0	49.5	66.2
Dawson	Diesel	P158	YM1	15.1	17.2	16.3	17.7
		Total Dawson Diesel		**221.3**	**304.2**	**263.3**	**372.8**
Faro	Diesel	P131	FD1	0.0	1.9		1.0
Faro	Diesel	P131	FD7	153.7	157.9	64.8	66.8
Faro	Diesel	YM	YM20	25.0	26.3	19.3	21.1
Faro	Diesel	YM	YM21	30.7	75.3	18.1	43.8
Faro	Diesel	YM	YM22	7.5	7.8	4.9	5.4
Faro	Diesel	YM	YM23	190.2	235.4	110.3	136.4
Faro	Diesel	YM	YM24	0.6	0.6	4.8	6.0
Faro	Diesel	YM	YM25	28.7	75.1	17.5	44.1
Faro	Diesel	YM	YM26	169.0	169.2	116.7	117.0
		Total Faro Diesel		**605.4**	**749.4**	**356.4**	**441.6**
Mayo	Diesel	P116	MD1	8.2	8.9	12.5	13.7
Mayo	Diesel	P116	MD2	16.6	17.6	24.8	26.1
Mayo	Diesel	P116	MD3	17.9	18.5	24.9	26.0
		Total Mayo Diesel		**42.6**	**45.0**	**62.3**	**65.8**
Whitehorse	Diesel	P126	WD4	8.0	35.0	3.8	16.8
Whitehorse	Diesel	P126	WD5	10.3	33.0	4.7	15.7
Whitehorse	Diesel	P126	WD6	24.0	50.3	12.0	24.0
Whitehorse	Diesel	P126	WD7	16.8	29.4	6.9	12.6
Whitehorse	Diesel	YM	YM10	134.7	281.7	82.9	168.6
Whitehorse	Diesel	YM	YM11	478.0	643.1	289.3	438.8
Whitehorse	Diesel	YM	YM12	510.3	667.8	322.9	400.9
Whitehorse	Diesel	YM	YM13	474.4	622.2	284.1	395.8
Whitehorse	Diesel	YM	YM14	592.8	678.1	355.1	409.3
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	598.7	702.6	347.9	415.5
Whitehorse	Diesel	YM	YM17	591.6	677.9	491.6	491.6
Whitehorse	Diesel	YM	YM18	572.1	596.5	335.0	389.0
Whitehorse	Diesel	YM	YM19	531.1	678.5	311.6	400.9
		Total Whitehorse Diesel		**4,542.7**	**5,821.6**	**2,847.8**	**3,654.4**
Whitehorse	LNG	WG0	WG1	0.0	0.0		
Whitehorse	LNG	WG0	WG2	2,695.7	4,592.4	639.0	1,100.0
Whitehorse	LNG	WG0	WG3	2,529.5	4,119.7	604.0	990.0
		Total Whitehorse LNG		**5,225.2**	**8,712.1**	**1,243.0**	**2,090.0**

		Total	Rental diesel
Whitehorse LNG		5,225.2	
Diesel		5,412.0	4,935.3
Whitehorse		4,542.7	4,483.6
Dawson		221.3	
Faro		605.4	451.7
Mayo		42.6	
Total thermal generation		10,637.2	4,935.3

YEC 2023/24 GRA
Mar-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.5	21.8	1.2	44.4
Dawson	Diesel	P158	DD2	0.7	58.4	1.2	81.9
Dawson	Diesel	P158	DD3	0.7	50.4	1.5	69.6
Dawson	Diesel	P158	DD4	0.8	85.1	1.3	98.2
Dawson	Diesel	P158	DD5	0.8	74.9	1.3	67.5
Dawson	Diesel	P158	YM1	1.5	18.7	1.8	19.5
Total Dawson Diesel				**5.0**	**309.2**	**8.3**	**381.1**
Faro	Diesel	P131	FD1	1.2	3.1	0.6	1.6
Faro	Diesel	P131	FD7	1.3	159.2	0.8	67.6
Faro	Diesel	YM	YM20	3.1	29.3	1.9	23.0
Faro	Diesel	YM	YM21	0.8	76.1	0.9	44.7
Faro	Diesel	YM	YM22	4.0	11.8	2.3	7.7
Faro	Diesel	YM	YM23	2.4	237.8	1.5	137.9
Faro	Diesel	YM	YM24	3.7	4.3	2.7	8.7
Faro	Diesel	YM	YM25	1.9	77.0	1.3	45.4
Faro	Diesel	YM	YM26	1.7	170.9	3.6	120.6
Total Faro Diesel				**20.0**	**769.4**	**15.6**	**457.2**
Mayo	Diesel	P116	MD1	1.1	9.9	1.3	15.0
Mayo	Diesel	P116	MD2	0.8	18.5	1.2	27.3
Mayo	Diesel	P116	MD3	0.8	19.3	1.2	27.2
Total Mayo Diesel				**2.7**	**47.7**	**3.7**	**69.5**
Whitehorse	Diesel	P126	WD4	5.0	40.0	2.1	18.9
Whitehorse	Diesel	P126	WD5	5.0	38.0	2.3	17.9
Whitehorse	Diesel	P126	WD6	5.0	55.3	2.0	26.0
Whitehorse	Diesel	P126	WD7	4.2	33.6	1.8	14.4
Whitehorse	Diesel	YM	YM10	57.7	339.4	38.1	206.7
Whitehorse	Diesel	YM	YM11	48.3	691.4	30.5	469.3
Whitehorse	Diesel	YM	YM12	62.8	730.6	39.3	440.2
Whitehorse	Diesel	YM	YM13	103.7	725.9	68.0	463.8
Whitehorse	Diesel	YM	YM14	60.9	739.0	39.8	449.1
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	60.7	763.3	41.6	457.1
Whitehorse	Diesel	YM	YM17	70.9	748.7	46.5	538.1
Whitehorse	Diesel	YM	YM18	62.9	659.4	41.6	430.6
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**547.0**	**6,368.6**	**353.6**	**4,008.0**
Whitehorse	LNG	WG0	WG1	0.0	0.0		
Whitehorse	LNG	WG0	WG2	275.7	4,868.1	72.0	1,172.0
Whitehorse	LNG	WG0	WG3	31.1	4,150.8	9.0	999.0
Total Whitehorse LNG				**306.8**	**9,018.9**	**81.0**	**2,171.0**

		Total	Rental diesel
Whitehorse LNG		306.8	
Diesel		574.8	545.3
Whitehorse		547.0	527.8
Dawson		5.0	
Faro		20.0	17.5
Mayo		2.7	
Total thermal generation		881.6	545.3

YEC 2023/24 GRA
Apr-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.6	22.4	1.1	45.5
Dawson	Diesel	P158	DD2	0.6	59.1	1.2	83.1
Dawson	Diesel	P158	DD3	0.7	51.1	1.1	70.7
Dawson	Diesel	P158	DD4	1.8	86.9	2.0	100.2
Dawson	Diesel	P158	DD5	2.5	77.3	2.0	69.5
Dawson	Diesel	P158	YM1	0.8	19.5	1.2	20.7
Total Dawson Diesel				**7.0**	**316.2**	**8.6**	**389.7**
Faro	Diesel	P131	FD1	2.9	6.0	1.5	3.1
Faro	Diesel	P131	FD7	1.7	160.9	1.3	68.9
Faro	Diesel	YM	YM20	21.2	50.6	14.2	37.2
Faro	Diesel	YM	YM21	34.0	110.0	19.7	64.4
Faro	Diesel	YM	YM22	11.7	23.5	8.9	16.6
Faro	Diesel	YM	YM23	36.3	274.1	22.9	160.8
Faro	Diesel	YM	YM24	9.6	13.9	6.3	15.0
Faro	Diesel	YM	YM25	49.0	126.0	28.7	74.1
Faro	Diesel	YM	YM26	49.9	220.7	29.0	149.6
Total Faro Diesel				**216.2**	**985.6**	**132.5**	**589.7**
Mayo	Diesel	P116	MD1	0.8	10.8	1.3	16.3
Mayo	Diesel	P116	MD2	0.8	19.3	1.2	28.4
Mayo	Diesel	P116	MD3	0.8	20.2	1.2	28.4
Total Mayo Diesel				**2.5**	**50.2**	**3.6**	**73.1**
Whitehorse	Diesel	P126	WD4	2.0	42.0	1.1	20.0
Whitehorse	Diesel	P126	WD5	3.4	41.4	1.5	19.4
Whitehorse	Diesel	P126	WD6	7.3	62.6	3.0	29.0
Whitehorse	Diesel	P126	WD7	5.0	38.6	1.6	16.0
Whitehorse	Diesel	YM	YM10	108.5	447.8	64.3	271.0
Whitehorse	Diesel	YM	YM11	97.4	788.8	62.2	531.5
Whitehorse	Diesel	YM	YM12	74.5	805.0	45.0	485.2
Whitehorse	Diesel	YM	YM13	88.5	814.4	54.1	517.9
Whitehorse	Diesel	YM	YM14	74.8	813.9	45.7	494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	53.3	816.6	33.8	490.9
Whitehorse	Diesel	YM	YM17	94.4	843.1	58.4	596.5
Whitehorse	Diesel	YM	YM18	74.3	733.7	47.1	477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**683.3**	**7,052.0**	**417.8**	**4,425.8**
Whitehorse	LNG	WG0	WG1	0.0	0.0		
Whitehorse	LNG	WG0	WG2	174.5	5,042.6	50.0	1,222.0
Whitehorse	LNG	WG0	WG3	83.7	4,234.5	24.0	1,023.0
Total Whitehorse LNG				**258.2**	**9,277.1**	**74.0**	**2,245.0**

		Total	Rental diesel
Whitehorse LNG		258.2	
Diesel		909.1	877.3
Whitehorse		683.3	665.6
Dawson		7.0	
Faro		216.2	211.6
Mayo		2.5	
Total thermal generation		1,167.3	877.3

YEC 2023/24 GRA
May-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.4	22.7	1.8	47.3
Dawson	Diesel	P158	DD2	0.7	59.8	2.1	85.2
Dawson	Diesel	P158	DD3	1.5	52.5	3.1	73.8
Dawson	Diesel	P158	DD4	3.7	90.5	5.4	105.6
Dawson	Diesel	P158	DD5	1.3	78.6	2.3	71.8
Dawson	Diesel	P158	YM1	1.1	20.6	1.1	21.8
Total Dawson Diesel				**8.5**	**324.7**	**15.8**	**405.5**
Faro	Diesel	P131	FD1	1.5	7.6	1.2	4.3
Faro	Diesel	P131	FD7	1.9	162.8	1.0	69.9
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		64.4
Faro	Diesel	YM	YM22	0.0	23.5		16.6
Faro	Diesel	YM	YM23	0.0	274.1		160.8
Faro	Diesel	YM	YM24	0.0	13.9		15.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**3.4**	**989.0**	**2.2**	**591.9**
Mayo	Diesel	P116	MD1	0.8	11.6	1.2	17.5
Mayo	Diesel	P116	MD2	0.8	20.2	1.1	29.6
Mayo	Diesel	P116	MD3	0.8	21.0	1.4	29.8
Total Mayo Diesel				**2.5**	**52.8**	**3.7**	**76.8**
Whitehorse	Diesel	P126	WD4	2.0	44.0	1.0	21.0
Whitehorse	Diesel	P126	WD5	3.0	44.4	1.3	20.8
Whitehorse	Diesel	P126	WD6	2.6	65.2	2.0	31.0
Whitehorse	Diesel	P126	WD7	5.9	44.5	2.7	18.7
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**13.5**	**7,065.4**	**7.0**	**4,432.8**
Whitehorse	LNG	WG0	WG1	113.5	113.5	27.0	27.0
Whitehorse	LNG	WG0	WG2	373.3	5,415.9	115.0	1,337.0
Whitehorse	LNG	WG0	WG3	86.2	4,320.7	23.0	1,046.0
Total Whitehorse LNG				**573.0**	**9,850.1**	**165.0**	**2,410.0**

		Total	Rental diesel
Whitehorse LNG		573.0	
Diesel		27.9	0.0
Whitehorse		13.5	0.0
Dawson		8.5	
Faro		3.4	0.0
Mayo		2.5	
Total thermal generation		600.9	0.0

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.3	23.0	2.1	49.4
Dawson	Diesel	P158	DD2	0.4	60.2	2.1	87.3
Dawson	Diesel	P158	DD3	0.5	53.0	2.3	76.1
Dawson	Diesel	P158	DD4	1.3	91.9	3.1	108.7
Dawson	Diesel	P158	DD5	6.6	85.2	18.2	90.0
Dawson	Diesel	P158	YM1	1.1	21.6	1.2	23.0
Total Dawson Diesel				**10.3**	**335.0**	**29.0**	**434.5**
Faro	Diesel	P131	FD1	2.3	9.8	1.1	5.3
Faro	Diesel	P131	FD7	9.5	172.2	17.1	87.0
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		64.4
Faro	Diesel	YM	YM22	0.0	23.5		16.6
Faro	Diesel	YM	YM23	0.0	274.1		160.8
Faro	Diesel	YM	YM24	0.0	13.9		15.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**11.7**	**1,000.8**	**18.2**	**610.0**
Mayo	Diesel	P116	MD1	0.8	12.4	1.2	18.7
Mayo	Diesel	P116	MD2	0.8	21.0	1.1	30.7
Mayo	Diesel	P116	MD3	0.6	21.6	0.9	30.7
Total Mayo Diesel				**2.3**	**55.1**	**3.3**	**80.1**
Whitehorse	Diesel	P126	WD4	0.0	44.0		21.0
Whitehorse	Diesel	P126	WD5	0.0	44.4		20.8
Whitehorse	Diesel	P126	WD6	0.0	65.2		31.0
Whitehorse	Diesel	P126	WD7	0.0	44.5		18.7
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**0.0**	**7,065.4**		**4,432.8**
Whitehorse	LNG	WG0	WG1	0.0	113.5		27.0
Whitehorse	LNG	WG0	WG2	0.0	5,415.9		1,337.0
Whitehorse	LNG	WG0	WG3	0.0	4,320.7		1,046.0
Total Whitehorse LNG				**0.0**	**9,850.1**		**2,410.0**

		Total	Rental diesel
Whitehorse LNG		0.0	
Diesel		24.3	0.0
Whitehorse		0.0	0.0
Dawson		10.3	
Faro		11.7	0.0
Mayo		2.3	
Total thermal generation		24.3	0.0

YEC 2023/24 GRA
Jul-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.5	23.5	1.3	50.7
Dawson	Diesel	P158	DD2	4.3	64.5	11.7	99.0
Dawson	Diesel	P158	DD3	132.4	185.4	217.1	293.2
Dawson	Diesel	P158	DD4	9.3	101.2	22.8	131.5
Dawson	Diesel	P158	DD5	0.6	85.9	1.1	91.1
Dawson	Diesel	P158	YM1	0.8	22.5	1.3	24.3
Total Dawson Diesel				**148.0**	**483.0**	**255.3**	**689.8**
Faro	Diesel	P131	FD1	2.3	12.1	1.1	6.4
Faro	Diesel	P131	FD7	1.3	173.5	1.1	88.1
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		64.4
Faro	Diesel	YM	YM22	0.0	23.5		16.6
Faro	Diesel	YM	YM23	0.0	274.1		160.8
Faro	Diesel	YM	YM24	0.0	13.9		15.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**3.6**	**1,004.3**	**2.2**	**612.2**
Mayo	Diesel	P116	MD1	0.6	13.1	1.0	19.7
Mayo	Diesel	P116	MD2	0.0	21.0	-0.4	30.3
Mayo	Diesel	P116	MD3	0.8	22.5	1.2	31.8
Total Mayo Diesel				**1.5**	**56.5**	**1.8**	**81.8**
Whitehorse	Diesel	P126	WD4	0.0	44.0		21.0
Whitehorse	Diesel	P126	WD5	0.0	44.4		20.8
Whitehorse	Diesel	P126	WD6	0.0	65.2		31.0
Whitehorse	Diesel	P126	WD7	0.0	44.5		18.7
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**0.0**	**7,065.4**		**4,432.8**
Whitehorse	LNG	WG0	WG1	0.0	113.5		27.0
Whitehorse	LNG	WG0	WG2	0.0	5,415.9		1,337.0
Whitehorse	LNG	WG0	WG3	0.0	4,320.7		1,046.0
Total Whitehorse LNG				**0.0**	**9,850.1**		**2,410.0**

		Total	Rental diesel
Whitehorse LNG		0.0	
Diesel		153.1	0.0
Whitehorse		0.0	0.0
Dawson		148.0	
Faro		3.6	0.0
Mayo		1.5	
Total thermal generation		153.1	0.0

YEC 2023/24 GRA
Aug-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	19.3	42.8	35.7	86.4
Dawson	Diesel	P158	DD2	375.3	439.8	506.9	605.9
Dawson	Diesel	P158	DD3	58.8	244.2	79.8	373.0
Dawson	Diesel	P158	DD4	4.2	105.5	7.8	139.3
Dawson	Diesel	P158	DD5	1.4	87.3	1.7	92.8
Dawson	Diesel	P158	YM1	0.6	23.1	1.1	25.4
Total Dawson Diesel				**459.7**	**942.7**	**633.0**	**1,322.8**
Faro	Diesel	P131	FD1	2.0	14.1	1.0	7.4
Faro	Diesel	P131	FD7	11.8	185.2	6.2	94.3
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		64.4
Faro	Diesel	YM	YM22	0.0	23.5		16.6
Faro	Diesel	YM	YM23	0.0	274.1		160.8
Faro	Diesel	YM	YM24	0.0	13.9		15.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**13.8**	**1,018.1**	**7.2**	**619.4**
Mayo	Diesel	P116	MD1	0.8	13.9	1.3	21.0
Mayo	Diesel	P116	MD2	0.2	21.2	1.3	31.6
Mayo	Diesel	P116	MD3	0.4	22.9	1.2	33.0
Total Mayo Diesel				**1.5**	**58.0**	**3.8**	**85.7**
Whitehorse	Diesel	P126	WD4	1.0	45.0	0.7	21.7
Whitehorse	Diesel	P126	WD5	2.1	46.5	1.2	22.0
Whitehorse	Diesel	P126	WD6	2.2	67.4	1.0	32.0
Whitehorse	Diesel	P126	WD7	1.7	46.2	1.3	20.0
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**33.9**	**7,099.4**	**4.2**	**4,437.0**
Whitehorse	LNG	WG0	WG1	0.0	113.5		27.0
Whitehorse	LNG	WG0	WG2	0.0	5,415.9		1,337.0
Whitehorse	LNG	WG0	WG3	0.0	4,320.7		1,046.0
Total Whitehorse LNG				**0.0**	**9,850.1**		**2,410.0**

		Total	Rental diesel
Whitehorse LNG		0.0	
Diesel		508.9	0.0
Whitehorse		33.9	0.0
Dawson		459.7	
Faro		13.8	0.0
Mayo		1.5	
Total thermal generation		508.9	0.0

YEC 2023/24 GRA
Sep-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	4.8	47.6	8.8	95.2
Dawson	Diesel	P158	DD2	10.4	450.2	15.2	621.1
Dawson	Diesel	P158	DD3	10.8	255.0	15.8	388.8
Dawson	Diesel	P158	DD4	1.9	107.3	2.3	141.6
Dawson	Diesel	P158	DD5	1.1	88.4	1.3	94.1
Dawson	Diesel	P158	YM1	1.3	24.4	1.3	26.7
Total Dawson Diesel				**30.2**	**972.8**	**44.7**	**1,367.5**
Faro	Diesel	P131	FD1	28.3	42.5	14.7	22.2
Faro	Diesel	P131	FD7	35.7	220.9	31.4	125.7
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		64.4
Faro	Diesel	YM	YM22	0.0	23.5		16.6
Faro	Diesel	YM	YM23	0.0	274.1		160.8
Faro	Diesel	YM	YM24	0.0	13.9		15.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**64.0**	**1,082.1**	**46.1**	**665.6**
Mayo	Diesel	P116	MD1	1.3	15.2	1.3	22.3
Mayo	Diesel	P116	MD2	0.6	21.8	1.5	33.1
Mayo	Diesel	P116	MD3	0.8	23.7	1.0	34.1
Total Mayo Diesel				**2.7**	**60.7**	**3.8**	**89.5**
Whitehorse	Diesel	P126	WD4	2.0	47.0	0.8	22.5
Whitehorse	Diesel	P126	WD5	2.1	48.6	0.9	22.9
Whitehorse	Diesel	P126	WD6	0.0	67.4		32.0
Whitehorse	Diesel	P126	WD7	0.0	46.2		20.0
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**4.1**	**7,076.5**	**1.7**	**4,438.7**
Whitehorse	LNG	WG0	WG1	0.0	113.5		27.0
Whitehorse	LNG	WG0	WG2	182.1	5,598.0	48.0	1,385.0
Whitehorse	LNG	WG0	WG3	73.2	4,393.9	18.0	1,064.0
Total Whitehorse LNG				**255.3**	**10,105.4**	**66.0**	**2,476.0**

		Total	Rental diesel
Whitehorse LNG		255.3	
Diesel		101.0	0.0
Whitehorse		4.1	0.0
Dawson		30.2	
Faro		64.0	0.0
Mayo		2.7	
Total thermal generation		356.3	0.0

YEC 2023/24 GRA
Oct-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	3.2	50.8	5.4	100.6
Dawson	Diesel	P158	DD2	5.3	455.6	7.4	628.5
Dawson	Diesel	P158	DD3	4.3	259.2	6.7	395.5
Dawson	Diesel	P158	DD4	13.2	120.5	18.2	159.8
Dawson	Diesel	P158	DD5	13.5	101.9	14.4	108.5
Dawson	Diesel	P158	YM1	1.1	25.4	1.7	28.4
Total Dawson Diesel				**40.7**	**1,013.5**	**53.8**	**1,421.3**
Faro	Diesel	P131	FD1	133.1	175.5	75.7	97.9
Faro	Diesel	P131	FD7	114.7	335.6	93.4	219.1
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0	2.3	66.7
Faro	Diesel	YM	YM22	0.0	23.5	6.2	22.8
Faro	Diesel	YM	YM23	0.0	274.1	4.1	164.9
Faro	Diesel	YM	YM24	0.0	13.9	7.0	22.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
Total Faro Diesel				**247.7**	**1,329.9**	**188.7**	**854.3**
Mayo	Diesel	P116	MD1	1.1	16.2	2.5	24.8
Mayo	Diesel	P116	MD2	0.8	22.7	1.7	34.8
Mayo	Diesel	P116	MD3	0.8	24.6	1.3	35.4
Total Mayo Diesel				**2.7**	**63.5**	**5.5**	**95.0**
Whitehorse	Diesel	P126	WD4	34.0	81.0	21.1	43.6
Whitehorse	Diesel	P126	WD5	29.7	78.3	17.0	40.0
Whitehorse	Diesel	P126	WD6	26.9	94.3	16.0	48.0
Whitehorse	Diesel	P126	WD7	22.7	68.9	10.3	30.3
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
Total Whitehorse Diesel				**113.3**	**7,189.8**	**64.5**	**4,503.2**
Whitehorse	LNG	WG0	WG1	13.7	127.2	4.0	31.0
Whitehorse	LNG	WG0	WG2	192.3	5,790.3	51.0	1,436.0
Whitehorse	LNG	WG0	WG3	132.5	4,526.4	36.0	1,100.0
Total Whitehorse LNG				**338.5**	**10,443.9**	**91.0**	**2,567.0**

		Total	Rental diesel
Whitehorse LNG		338.5	
Diesel		404.4	0.0
Whitehorse		113.3	0.0
Dawson		40.7	
Faro		247.7	0.0
Mayo		2.7	
Total thermal generation		742.9	0.0

YEC 2023/24 GRA
Nov-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	37.7	88.6	69.9	170.5
Dawson	Diesel	P158	DD2	50.7	506.3	71.8	700.3
Dawson	Diesel	P158	DD3	74.8	334.1	104.3	499.8
Dawson	Diesel	P158	DD4	101.7	222.3	115.8	275.6
Dawson	Diesel	P158	DD5	159.1	261.0	130.8	239.3
Dawson	Diesel	P158	YM1	1.9	27.3	2.4	30.8
		Total Dawson Diesel		**426.0**	**1,439.4**	**495.0**	**1,916.3**
Faro	Diesel	P131	FD1	13.9	189.5	6.0	103.8
Faro	Diesel	P131	FD7	52.5	388.1	26.2	245.3
Faro	Diesel	YM	YM20	0.0	50.6		37.2
Faro	Diesel	YM	YM21	0.0	110.0		66.7
Faro	Diesel	YM	YM22	0.0	23.5		22.8
Faro	Diesel	YM	YM23	0.0	274.1		164.9
Faro	Diesel	YM	YM24	0.0	13.9		22.0
Faro	Diesel	YM	YM25	0.0	126.0		74.1
Faro	Diesel	YM	YM26	0.0	220.7		149.6
		Total Faro Diesel		**66.4**	**1,396.3**	**32.2**	**886.4**
Mayo	Diesel	P116	MD1	6.5	22.7	8.0	32.8
Mayo	Diesel	P116	MD2	0.0	22.7	0.0	34.8
Mayo	Diesel	P116	MD3	6.1	30.7	7.6	43.0
		Total Mayo Diesel		**12.6**	**76.1**	**15.7**	**110.6**
Whitehorse	Diesel	P126	WD4	14.0	95.0	9.0	52.6
Whitehorse	Diesel	P126	WD5	251.1	329.4	114.7	154.7
Whitehorse	Diesel	P126	WD6	228.3	322.6	106.0	154.0
Whitehorse	Diesel	P126	WD7	337.7	406.6	135.8	166.1
Whitehorse	Diesel	YM	YM10	0.0	447.8		271.0
Whitehorse	Diesel	YM	YM11	0.0	788.8		531.5
Whitehorse	Diesel	YM	YM12	0.0	805.0		485.2
Whitehorse	Diesel	YM	YM13	0.0	814.4		517.9
Whitehorse	Diesel	YM	YM14	0.0	813.9		494.8
Whitehorse	Diesel	YM	YM15	0.0	125.5		74.9
Whitehorse	Diesel	YM	YM16	0.0	816.6		490.9
Whitehorse	Diesel	YM	YM17	0.0	843.1		596.5
Whitehorse	Diesel	YM	YM18	0.0	733.7		477.7
Whitehorse	Diesel	YM	YM19	0.0	678.5		400.9
		Total Whitehorse Diesel		**831.1**	**8,020.9**	**365.5**	**4,868.7**
Whitehorse	LNG	WG0	WG1	1,261.3	1,388.5	316.0	347.0
Whitehorse	LNG	WG0	WG2	1,629.2	7,419.5	413.0	1,849.0
Whitehorse	LNG	WG0	WG3	1,375.5	5,901.9	348.0	1,448.0
		Total Whitehorse LNG		**4,266.0**	**14,709.9**	**1,077.0**	**3,644.0**

		Total	Rental diesel
Whitehorse LNG		4,266.0	
Diesel		1,336.1	0.0
Whitehorse		831.1	0.0
Dawson		426.0	
Faro		66.4	0.0
Mayo		12.6	
Total thermal generation		5,602.1	0.0

YEC 2023/24 GRA
Dec-21 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	27.4	116.0	46.3	216.8
Dawson	Diesel	P158	DD2	36.1	542.4	47.2	747.5
Dawson	Diesel	P158	DD3	45.7	379.8	60.3	560.1
Dawson	Diesel	P158	DD4	136.2	358.5	146.5	422.1
Dawson	Diesel	P158	DD5	113.3	374.3	93.6	332.9
Dawson	Diesel	P158	YM1	0.0	27.3		30.8
			Total Dawson Diesel	**358.8**	**1,798.2**	**393.9**	**2,310.2**
Faro	Diesel	P131	FD1	0.0	189.5		103.8
Faro	Diesel	P131	FD7	34.0	422.1	15.7	261.0
Faro	Diesel	YM	YM20	112.7	163.3	64.3	101.5
Faro	Diesel	YM	YM21	43.3	153.3	30.6	97.3
Faro	Diesel	YM	YM22	33.1	56.6	14.5	37.3
Faro	Diesel	YM	YM23	131.4	405.5	72.4	237.3
Faro	Diesel	YM	YM24	9.8	23.6	2.0	24.0
Faro	Diesel	YM	YM25	227.7	353.7	126.0	200.1
Faro	Diesel	YM	YM26	219.7	440.4	121.2	270.8
			Total Faro Diesel	**811.6**	**2,207.9**	**446.7**	**1,333.1**
Mayo	Diesel	P116	MD1	0.6	23.4	1.2	34.0
Mayo	Diesel	P116	MD2	0.2	22.9		34.8
Mayo	Diesel	P116	MD3	0.4	31.1	1.1	44.1
			Total Mayo Diesel	**1.3**	**77.3**	**2.3**	**112.9**
Whitehorse	Diesel	P126	WD4	0.0	95.0		52.6
Whitehorse	Diesel	P126	WD5	51.1	380.5	22.9	177.5
Whitehorse	Diesel	P126	WD6	78.7	401.3	36.0	190.0
Whitehorse	Diesel	P126	WD7	167.8	574.4	67.3	233.4
Whitehorse	Diesel	YM	YM10	670.4	1,118.3	401.7	672.7
Whitehorse	Diesel	YM	YM11	688.8	1,477.6	404.6	936.1
Whitehorse	Diesel	YM	YM12	700.8	1,505.8	404.7	889.9
Whitehorse	Diesel	YM	YM13	515.4	1,329.8	304.6	822.5
Whitehorse	Diesel	YM	YM14	704.4	1,518.3	405.2	900.0
Whitehorse	Diesel	YM	YM15	713.6	839.1	402.2	477.1
Whitehorse	Diesel	YM	YM16		816.6	365.4	856.3
Whitehorse	Diesel	YM	YM17	208.6	1,051.7	122.9	719.4
Whitehorse	Diesel	YM	YM18	601.8	1,335.5	345.6	823.3
Whitehorse	Diesel	YM	YM19	465.0	1,143.6	255.1	656.0
			Total Whitehorse Diesel	**5,566.5**	**13,587.4**	**3,538.2**	**8,406.8**
Whitehorse	LNG	WG0	WG1	2,689.1	4,077.6	635.0	982.0
Whitehorse	LNG	WG0	WG2	1,327.9	8,747.4	320.0	2,169.0
Whitehorse	LNG	WG0	WG3	2,818.5	8,720.4	667.0	2,115.0
			Total Whitehorse LNG	**6,835.5**	**21,545.4**	**1,622.0**	**5,266.0**

		Total	Rental diesel
Whitehorse LNG		6,835.5	
Diesel		6,738.1	6,046.5
Whitehorse		5,566.5	5,268.9
Dawson		358.8	
Faro		811.6	777.6
Mayo		1.3	
Total thermal generation		13,573.6	6,046.5

YEC 2023/24 GRA
Jan-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	59.5	59.5	104.4	104.4
Dawson	Diesel	P158	DD2	90.6	90.6	115.4	115.4
Dawson	Diesel	P158	DD3	94.9	94.9	119.9	119.9
Dawson	Diesel	P158	DD4	182.7	182.7	189.2	189.2
Dawson	Diesel	P158	DD5	188.6	188.6	151.0	151.0
Dawson	Diesel	P158	YM1	27.3	27.3	32.7	32.7
Total Dawson Diesel				**643.5**	**643.5**	**712.6**	**712.6**
Faro	Diesel	P131	FD1	0.0	0.0		
Faro	Diesel	P131	FD7	157.1	157.1	63.5	63.5
Faro	Diesel	YM	YM20	229.1	229.1	130.5	130.5
Faro	Diesel	YM	YM21	69.5	69.5	35.9	35.9
Faro	Diesel	YM	YM22	110.0	110.0	65.5	65.5
Faro	Diesel	YM	YM23	340.0	340.0	189.8	189.8
Faro	Diesel	YM	YM24	11.4	11.4	10.3	10.3
Faro	Diesel	YM	YM25	337.2	337.2	189.0	189.0
Faro	Diesel	YM	YM26	239.4	239.4	133.6	133.6
Total Faro Diesel				**1,493.7**	**1,493.7**	**818.1**	**818.1**
Mayo	Diesel	P116	MD1	43.1	43.1	52.9	52.9
Mayo	Diesel	P116	MD2	0.0	0.0	0.2	0.2
Mayo	Diesel	P116	MD3	42.6	42.6	52.6	52.6
Total Mayo Diesel				**85.7**	**85.7**	**105.8**	**105.8**
Whitehorse	Diesel	P126	WD4	0.0	0.0		
Whitehorse	Diesel	P126	WD5	57.8	57.8	24.6	24.6
Whitehorse	Diesel	P126	WD6	80.2	80.2	35.0	35.0
Whitehorse	Diesel	P126	WD7	213.6	213.6	80.6	80.6
Whitehorse	Diesel	YM	YM10	365.2	365.2	211.3	211.3
Whitehorse	Diesel	YM	YM11	338.3	338.3	193.6	193.6
Whitehorse	Diesel	YM	YM12	314.2	314.2	182.0	182.0
Whitehorse	Diesel	YM	YM13	346.8	346.8	200.1	200.1
Whitehorse	Diesel	YM	YM14	376.1	376.1	213.8	213.8
Whitehorse	Diesel	YM	YM15	187.0	187.0	105.8	105.8
Whitehorse	Diesel	YM	YM16	437.1	437.1	244.2	244.2
Whitehorse	Diesel	YM	YM17	236.9	236.9	133.6	133.6
Whitehorse	Diesel	YM	YM18	420.1	420.1	244.6	244.6
Whitehorse	Diesel	YM	YM19	378.0	378.0	211.3	211.3
Total Whitehorse Diesel				**3,751.4**	**3,751.4**	**2,080.4**	**2,080.4**
Whitehorse	LNG	WG0	WG1	2,085.6	2,085.6	496.0	496.0
Whitehorse	LNG	WG0	WG2	794.9	794.9	204.0	204.0
Whitehorse	LNG	WG0	WG3	2,243.7	2,243.7	540.0	540.0
Total Whitehorse LNG				**5,124.2**	**5,124.2**	**1,240.0**	**1,240.0**

		Total	Rental diesel
Whitehorse LNG		5,124.2	
Diesel		5,974.3	4,736.5
Whitehorse		3,751.4	3,399.9
Dawson		643.5	
Faro		1,493.7	1,336.6
Mayo		85.7	
Total thermal generation		11,098.5	4,736.5

YEC 2023/24 GRA
Feb-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	7.8	67.3	23.7	128.1
Dawson	Diesel	P158	DD2	46.1	136.7	80.4	195.8
Dawson	Diesel	P158	DD3	48.7	143.6	82.1	202.0
Dawson	Diesel	P158	DD4	20.7	203.5	31.8	221.0
Dawson	Diesel	P158	DD5	85.0	273.6	86.0	237.0
Dawson	Diesel	P158	YM1	36.8	64.1	41.4	74.1
		Total Dawson Diesel		**245.1**	**888.6**	**345.4**	**1,058.0**
Faro	Diesel	P131	FD1	3.3	3.3	1.6	1.6
Faro	Diesel	P131	FD7	3.4	160.4	1.8	65.3
Faro	Diesel	YM	YM20	45.1	274.2	26.3	156.8
Faro	Diesel	YM	YM21	70.2	139.7	40.5	76.4
Faro	Diesel	YM	YM22	27.7	137.7	16.1	81.6
Faro	Diesel	YM	YM23	77.3	417.3	43.9	233.7
Faro	Diesel	YM	YM24	108.9	120.3	63.2	73.5
Faro	Diesel	YM	YM25	67.1	404.3	38.5	227.5
Faro	Diesel	YM	YM26	91.6	331.1	52.0	185.6
		Total Faro Diesel		**494.6**	**1,988.3**	**283.9**	**1,102.0**
Mayo	Diesel	P116	MD1	0.6	43.7	1.1	54.0
Mayo	Diesel	P116	MD2	0.0	0.0	0.6	0.8
Mayo	Diesel	P116	MD3	0.6	43.3	1.1	53.7
		Total Mayo Diesel		**1.3**	**86.9**	**2.8**	**108.5**
Whitehorse	Diesel	P126	WD4	3.0	3.0	1.7	1.7
Whitehorse	Diesel	P126	WD5	0.0	57.8		24.6
Whitehorse	Diesel	P126	WD6	0.0	80.2		35.0
Whitehorse	Diesel	P126	WD7	0.4	214.0		80.6
Whitehorse	Diesel	YM	YM10	0.0	365.2	0.4	211.7
Whitehorse	Diesel	YM	YM11	1.3	339.6	1.3	194.9
Whitehorse	Diesel	YM	YM12	8.3	322.5	5.8	187.8
Whitehorse	Diesel	YM	YM13	11.7	358.5	7.9	208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1	0.1	213.9
Whitehorse	Diesel	YM	YM15	24.6	211.6	14.1	119.9
Whitehorse	Diesel	YM	YM16	12.5	449.6	8.6	252.8
Whitehorse	Diesel	YM	YM17	11.9	248.8	7.7	141.3
Whitehorse	Diesel	YM	YM18	4.2	424.3	2.4	247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
		Total Whitehorse Diesel		**77.8**	**3,829.2**	**50.0**	**2,130.4**
Whitehorse	LNG	WG0	WG1	729.6	2,815.2	177.0	673.0
Whitehorse	LNG	WG0	WG2	1,268.4	2,063.3	318.0	522.0
Whitehorse	LNG	WG0	WG3	795.7	3,039.4	197.0	737.0
		Total Whitehorse LNG		**2,793.7**	**7,917.9**	**692.0**	**1,932.0**

		Total	Rental diesel
Whitehorse LNG		2,793.7	
Diesel		818.8	562.3
Whitehorse		77.8	74.4
Dawson		245.1	
Faro		494.6	488.0
Mayo		1.3	
Total thermal generation		3,612.5	562.3

YEC 2023/24 GRA
Mar-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	3.0	139.7	4.9	200.7
Dawson	Diesel	P158	DD3	4.5	148.1	7.2	209.2
Dawson	Diesel	P158	DD4	3.6	207.1	4.2	225.2
Dawson	Diesel	P158	DD5	7.3	280.9	7.5	244.5
Dawson	Diesel	P158	YM1	1.5	65.5	1.6	75.7
Total Dawson Diesel				**19.9**	**908.5**	**25.4**	**1,083.4**
Faro	Diesel	P131	FD1	6.9	10.2	3.6	5.2
Faro	Diesel	P131	FD7	6.7	167.2	3.9	69.2
Faro	Diesel	YM	YM20	26.0	300.2	15.7	172.5
Faro	Diesel	YM	YM21	2.8	142.5	2.1	78.5
Faro	Diesel	YM	YM22	5.2	142.9	3.2	84.8
Faro	Diesel	YM	YM23	20.2	437.5	11.9	245.6
Faro	Diesel	YM	YM24	10.1	130.4	6.1	79.6
Faro	Diesel	YM	YM25	26.1	430.4	15.0	242.5
Faro	Diesel	YM	YM26	11.2	342.2	6.5	192.1
Total Faro Diesel				**115.1**	**2,103.4**	**68.0**	**1,170.0**
Mayo	Diesel	P116	MD1	0.8	44.5	1.2	55.2
Mayo	Diesel	P116	MD2	0.0	0.0	0.4	1.3
Mayo	Diesel	P116	MD3	0.8	44.1	1.3	55.0
Total Mayo Diesel				**1.7**	**88.6**	**2.9**	**111.5**
Whitehorse	Diesel	P126	WD4	2.0	5.0	1.1	2.8
Whitehorse	Diesel	P126	WD5	5.0	62.7	2.2	26.8
Whitehorse	Diesel	P126	WD6	4.9	85.1	3.0	38.0
Whitehorse	Diesel	P126	WD7	9.2	223.2	2.7	83.3
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
Total Whitehorse Diesel				**21.1**	**3,850.3**	**9.0**	**2,139.4**
Whitehorse	LNG	WG0	WG1	275.8	3,091.0	73.0	746.0
Whitehorse	LNG	WG0	WG2	796.2	2,859.5	207.0	729.0
Whitehorse	LNG	WG0	WG3	417.1	3,456.5	112.0	849.0
Total Whitehorse LNG				**1,489.1**	**9,407.0**	**392.0**	**2,324.0**

		Total	Rental diesel
Whitehorse LNG		1,489.1	
Diesel		157.8	101.5
Whitehorse		21.1	0.0
Dawson		19.9	
Faro		115.1	101.5
Mayo		1.7	
Total thermal generation		1,646.9	101.5

YEC 2023/24 GRA
Apr-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	7.6	147.3	11.8	212.5
Dawson	Diesel	P158	DD3	12.5	160.6	18.0	227.2
Dawson	Diesel	P158	DD4	0.0	207.1		225.2
Dawson	Diesel	P158	DD5	16.4	297.4	16.4	260.9
Dawson	Diesel	P158	YM1	0.0	65.5		75.7
			Total Dawson Diesel	**36.6**	**945.1**	**46.2**	**1,129.6**
Faro	Diesel	P131	FD1	1.8	12.0	1.0	6.2
Faro	Diesel	P131	FD7	2.1	169.3	1.2	70.4
Faro	Diesel	YM	YM20	0.0	300.2		172.5
Faro	Diesel	YM	YM21	0.0	142.5		78.5
Faro	Diesel	YM	YM22	0.0	142.9		84.8
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4		79.6
Faro	Diesel	YM	YM25	0.0	430.4		242.5
Faro	Diesel	YM	YM26	0.0	342.2		192.1
			Total Faro Diesel	**3.9**	**2,107.3**	**2.2**	**1,172.2**
Mayo	Diesel	P116	MD1	1.1	45.6	1.4	56.6
Mayo	Diesel	P116	MD2	0.6	0.6	1.3	2.5
Mayo	Diesel	P116	MD3	0.8	44.9	1.4	56.3
			Total Mayo Diesel	**2.5**	**91.1**	**4.0**	**115.4**
Whitehorse	Diesel	P126	WD4	14.0	19.0	6.0	8.8
Whitehorse	Diesel	P126	WD5	12.1	74.8	5.4	32.2
Whitehorse	Diesel	P126	WD6	12.7	97.8	5.0	43.0
Whitehorse	Diesel	P126	WD7	33.6	256.8	15.1	98.3
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
			Total Whitehorse Diesel	**72.4**	**3,922.7**	**31.5**	**2,170.9**
Whitehorse	LNG	WG0	WG1	261.8	3,352.8	68.0	814.0
Whitehorse	LNG	WG0	WG2	62.2	2,921.7	17.0	746.0
Whitehorse	LNG	WG0	WG3	410.3	3,866.8	106.0	955.0
			Total Whitehorse LNG	**734.3**	**10,141.3**	**191.0**	**2,515.0**

		Total	Rental diesel
Whitehorse LNG		734.3	
Diesel		115.4	0.0
Whitehorse		72.4	0.0
Dawson		36.6	
Faro		3.9	0.0
Mayo		2.5	
Total thermal generation		849.7	0.0

YEC 2023/24 GRA
May-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	2.5	149.8	4.5	217.0
Dawson	Diesel	P158	DD3	3.4	164.0	5.9	233.1
Dawson	Diesel	P158	DD4	2.1	209.1	3.1	228.3
Dawson	Diesel	P158	DD5	11.9	309.2	10.5	271.4
Dawson	Diesel	P158	YM1	1.7	67.2	2.3	78.0
Total Dawson Diesel				**21.5**	**966.6**	**26.3**	**1,155.9**
Faro	Diesel	P131	FD1	2.1	14.1	1.0	7.3
Faro	Diesel	P131	FD7	2.1	171.4	1.1	71.4
Faro	Diesel	YM	YM20	0.0	300.2		172.5
Faro	Diesel	YM	YM21	0.0	142.5		78.5
Faro	Diesel	YM	YM22	0.0	142.9		84.8
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4		79.6
Faro	Diesel	YM	YM25	0.0	430.4		242.5
Faro	Diesel	YM	YM26	0.0	342.2		192.1
Total Faro Diesel				**4.2**	**2,111.5**	**2.1**	**1,174.3**
Mayo	Diesel	P116	MD1	0.4	46.0	1.1	57.7
Mayo	Diesel	P116	MD2	0.6	1.3	0.4	2.9
Mayo	Diesel	P116	MD3	0.0	44.9	0.3	56.7
Total Mayo Diesel				**1.1**	**92.2**	**1.8**	**117.3**
Whitehorse	Diesel	P126	WD4	0.0	19.0		8.8
Whitehorse	Diesel	P126	WD5	0.0	74.8		32.2
Whitehorse	Diesel	P126	WD6	0.0	97.8		43.0
Whitehorse	Diesel	P126	WD7	8.8	265.7	4.4	102.7
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
Total Whitehorse Diesel				**8.8**	**3,931.5**	**4.4**	**2,175.2**
Whitehorse	LNG	WG0	WG1	37.5	3,390.3	12.0	826.0
Whitehorse	LNG	WG0	WG2	7.2	2,928.9	3.0	749.0
Whitehorse	LNG	WG0	WG3	176.0	4,042.8	49.0	1,004.0
Total Whitehorse LNG				**220.7**	**10,362.0**	**64.0**	**2,579.0**

		Total	Rental diesel
Whitehorse LNG		220.7	
Diesel		35.6	0.0
Whitehorse		8.8	0.0
Dawson		21.5	
Faro		4.2	0.0
Mayo		1.1	
Total thermal generation		256.3	0.0

YEC 2023/24 GRA
Jun-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	0.2	150.0	1.3	218.3
Dawson	Diesel	P158	DD3	1.0	165.0	3.2	236.3
Dawson	Diesel	P158	DD4	4.1	213.2	7.6	235.9
Dawson	Diesel	P158	DD5	6.3	315.5	10.4	281.8
Dawson	Diesel	P158	YM1	0.8	68.0	1.2	79.2
			Total Dawson Diesel	**12.4**	**979.1**	**23.7**	**1,179.6**
Faro	Diesel	P131	FD1	1.9	16.0	0.9	8.2
Faro	Diesel	P131	FD7	2.5	173.9	1.6	73.0
Faro	Diesel	YM	YM20	0.0	300.2		172.5
Faro	Diesel	YM	YM21	0.0	142.5		78.5
Faro	Diesel	YM	YM22	0.0	142.9		84.8
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4		79.6
Faro	Diesel	YM	YM25	0.0	430.4		242.5
Faro	Diesel	YM	YM26	0.0	342.2		192.1
			Total Faro Diesel	**4.4**	**2,116.0**	**2.5**	**1,176.8**
Mayo	Diesel	P116	MD1	2.5	48.5	4.0	61.7
Mayo	Diesel	P116	MD2	1.1	2.3	2.2	5.2
Mayo	Diesel	P116	MD3	1.5	46.4	2.0	58.7
			Total Mayo Diesel	**5.0**	**97.2**	**8.2**	**125.5**
Whitehorse	Diesel	P126	WD4	15.0	34.0	8.9	17.7
Whitehorse	Diesel	P126	WD5	11.6	86.3	7.7	39.8
Whitehorse	Diesel	P126	WD6	5.3	103.1	4.0	47.0
Whitehorse	Diesel	P126	WD7	4.2	269.9	3.9	106.6
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
			Total Whitehorse Diesel	**36.1**	**3,967.5**	**24.4**	**2,199.7**
Whitehorse	LNG	WG0	WG1	0.0	3,390.3		826.0
Whitehorse	LNG	WG0	WG2	52.4	2,981.3	15.0	764.0
Whitehorse	LNG	WG0	WG3	0.0	4,042.8		1,004.0
			Total Whitehorse LNG	**52.4**	**10,414.4**	**15.0**	**2,594.0**

		Total	Rental diesel
Whitehorse LNG		52.4	
Diesel		58.0	0.0
Whitehorse		36.1	0.0
Dawson		12.4	
Faro		4.4	0.0
Mayo		5.0	
Total thermal generation		110.4	0.0

YEC 2023/24 GRA
Jul-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	4.5	154.5	9.5	227.8
Dawson	Diesel	P158	DD3	6.0	170.9	11.6	247.9
Dawson	Diesel	P158	DD4	1.9	215.2	3.8	239.7
Dawson	Diesel	P158	DD5	9.7	325.2	12.0	293.8
Dawson	Diesel	P158	YM1	1.5	69.5	1.9	81.1
			Total Dawson Diesel	**23.6**	**1,002.6**	**38.8**	**1,218.4**
Faro	Diesel	P131	FD1	1.9	17.9	1.0	9.2
Faro	Diesel	P131	FD7	2.1	176.0	2.3	75.3
Faro	Diesel	YM	YM20	0.0	300.2		172.5
Faro	Diesel	YM	YM21	0.0	142.5		78.5
Faro	Diesel	YM	YM22	0.0	142.9		84.8
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4		79.6
Faro	Diesel	YM	YM25	0.0	430.4		242.5
Faro	Diesel	YM	YM26	0.0	342.2		192.1
			Total Faro Diesel	**4.0**	**2,120.0**	**3.3**	**1,180.1**
Mayo	Diesel	P116	MD1	-0.4	48.1	1.2	62.8
Mayo	Diesel	P116	MD2	1.1	3.4	2.1	7.3
Mayo	Diesel	P116	MD3	0.0	46.4	1.2	59.9
			Total Mayo Diesel	**0.6**	**97.9**	**4.5**	**130.0**
Whitehorse	Diesel	P126	WD4	10.0	44.0	8.1	25.8
Whitehorse	Diesel	P126	WD5	15.8	102.2	10.4	50.2
Whitehorse	Diesel	P126	WD6	0.0	103.1		47.0
Whitehorse	Diesel	P126	WD7	27.3	297.2	14.0	120.6
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
			Total Whitehorse Diesel	**53.1**	**4,020.6**	**32.5**	**2,232.2**
Whitehorse	LNG	WG0	WG1	152.0	3,542.3	41.0	867.0
Whitehorse	LNG	WG0	WG2	26.3	3,007.6	6.0	770.0
Whitehorse	LNG	WG0	WG3	184.7	4,227.5	55.0	1,059.0
			Total Whitehorse LNG	**363.0**	**10,777.4**	**102.0**	**2,696.0**

		Total	Rental diesel
Whitehorse LNG		363.0	
Diesel		81.3	0.0
Whitehorse		53.1	0.0
Dawson		23.6	
Faro		4.0	0.0
Mayo		0.6	
Total thermal generation		444.3	0.0

YEC 2023/24 GRA
Aug-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	0.0	67.3		128.1
Dawson	Diesel	P158	DD2	1.4	155.9	7.0	234.8
Dawson	Diesel	P158	DD3	10.2	181.1	20.9	268.8
Dawson	Diesel	P158	DD4	16.7	231.9	22.1	261.8
Dawson	Diesel	P158	DD5	18.6	343.8	25.2	319.0
Dawson	Diesel	P158	YM1	1.7	71.2	1.8	82.9
Total Dawson Diesel				**48.6**	**1,051.2**	**77.0**	**1,295.4**
Faro	Diesel	P131	FD1	2.9	20.8	1.3	10.6
Faro	Diesel	P131	FD7	2.9	178.9	1.2	76.5
Faro	Diesel	YM	YM20	2.3	302.5	3.1	175.6
Faro	Diesel	YM	YM21	0.0	142.5	0.1	78.6
Faro	Diesel	YM	YM22	0.0	142.9	0.1	84.9
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4	0.2	79.8
Faro	Diesel	YM	YM25	3.5	433.8	2.1	244.6
Faro	Diesel	YM	YM26	0.3	342.6	0.6	192.7
Total Faro Diesel				**11.9**	**2,131.9**	**8.7**	**1,188.9**
Mayo	Diesel	P116	MD1	2.3	50.4	1.6	64.4
Mayo	Diesel	P116	MD2	1.5	4.8	1.2	8.5
Mayo	Diesel	P116	MD3	1.9	48.3	1.2	61.0
Total Mayo Diesel				**5.7**	**103.5**	**3.9**	**133.9**
Whitehorse	Diesel	P126	WD4	2.0	46.0	1.1	26.9
Whitehorse	Diesel	P126	WD5	4.7	106.9	2.5	52.7
Whitehorse	Diesel	P126	WD6	11.9	115.0	6.0	53.0
Whitehorse	Diesel	P126	WD7	16.8	314.0	7.3	127.9
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
Total Whitehorse Diesel				**35.4**	**4,056.1**	**16.9**	**2,249.1**
Whitehorse	LNG	WG0	WG1	112.8	3,655.1	33.0	900.0
Whitehorse	LNG	WG0	WG2	82.6	3,090.2	23.0	793.0
Whitehorse	LNG	WG0	WG3	86.7	4,314.2	26.0	1,085.0
Total Whitehorse LNG				**282.1**	**11,059.5**	**82.0**	**2,778.0**

		Total	Rental diesel
Whitehorse LNG		282.1	
Diesel		101.6	6.1
Whitehorse		35.4	0.0
Dawson		48.6	
Faro		11.9	6.1
Mayo		5.7	
Total thermal generation		383.7	6.1

YEC 2023/24 GRA
Sep-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	3.5	70.8	9.0	137.1
Dawson	Diesel	P158	DD2	2.4	158.4	5.0	239.8
Dawson	Diesel	P158	DD3	1.9	183.0	2.9	271.7
Dawson	Diesel	P158	DD4	9.9	241.8	11.9	273.7
Dawson	Diesel	P158	DD5	19.9	363.7	32.4	351.4
Dawson	Diesel	P158	YM1	1.7	72.9	1.7	84.6
Total Dawson Diesel				**39.3**	**1,090.5**	**62.9**	**1,358.3**
Faro	Diesel	P131	FD1	2.3	23.2	1.2	11.7
Faro	Diesel	P131	FD7	419.6	598.5	439.6	516.1
Faro	Diesel	YM	YM20	0.0	302.5		175.6
Faro	Diesel	YM	YM21	0.0	142.5		78.6
Faro	Diesel	YM	YM22	0.0	142.9		84.9
Faro	Diesel	YM	YM23	0.0	437.5		245.6
Faro	Diesel	YM	YM24	0.0	130.4		79.8
Faro	Diesel	YM	YM25	0.0	433.8		244.6
Faro	Diesel	YM	YM26	0.0	342.6	241,459.0	241,651.7
Total Faro Diesel				**421.9**	**2,553.8**	**241,899.8**	**243,088.6**
Mayo	Diesel	P116	MD1	1.3	51.7	1.5	65.9
Mayo	Diesel	P116	MD2	0.0	4.8	1.1	9.6
Mayo	Diesel	P116	MD3	1.1	49.4	1.4	62.5
Total Mayo Diesel				**2.3**	**105.8**	**4.0**	**137.9**
Whitehorse	Diesel	P126	WD4	0.0	46.0	1.6	28.5
Whitehorse	Diesel	P126	WD5	1.4	108.3	1.5	54.1
Whitehorse	Diesel	P126	WD6	0.5	115.5	1.0	54.0
Whitehorse	Diesel	P126	WD7	0.4	314.4	1.3	129.2
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
Total Whitehorse Diesel				**2.4**	**4,058.4**	**5.3**	**2,254.4**
Whitehorse	LNG	WG0	WG1	111.9	3,767.0	27.0	927.0
Whitehorse	LNG	WG0	WG2	0.0	3,090.2		793.0
Whitehorse	LNG	WG0	WG3	58.3	4,372.5	17.0	1,102.0
Total Whitehorse LNG				**170.2**	**11,229.7**	**44.0**	**2,822.0**

		Total	Rental diesel
Whitehorse LNG		170.2	
Diesel		465.9	0.0
Whitehorse		2.4	0.0
Dawson		39.3	
Faro		421.9	0.0
Mayo		2.3	
Total thermal generation		636.1	0.0

YEC 2023/24 GRA
Oct-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	35.2	106.0	53.6	190.7
Dawson	Diesel	P158	DD2	54.4	212.8	69.4	309.2
Dawson	Diesel	P158	DD3	68.2	251.2	88.1	359.8
Dawson	Diesel	P158	DD4	128.8	370.5	104.7	378.4
Dawson	Diesel	P158	DD5	141.6	505.3	119.5	470.9
Dawson	Diesel	P158	YM1	0.6	73.5	1.1	85.7
Total Dawson Diesel				**428.8**	**1,519.3**	**436.4**	**1,794.7**
Faro	Diesel	P131	FD1	24.0	47.2	10.7	22.4
Faro	Diesel	P131	FD7	10.1	608.6	29,472.3	29,988.4
Faro	Diesel	YM	YM20	5.5	307.9	3.4	179.0
Faro	Diesel	YM	YM21	6.6	149.1	3.8	82.4
Faro	Diesel	YM	YM22	6.1	149.0	2.6	87.5
Faro	Diesel	YM	YM23	6.1	443.6	4.0	249.6
Faro	Diesel	YM	YM24	4.0	134.3	2.2	82.0
Faro	Diesel	YM	YM25	0.0	433.8		244.6
Faro	Diesel	YM	YM26	6.1	348.7	-241,455.4	196.3
Total Faro Diesel				**68.4**	**2,622.2**	**-211,956.4**	**31,132.2**
Mayo	Diesel	P116	MD1	1.7	53.3	247,004.4	247,070.3
Mayo	Diesel	P116	MD2	2.1	6.9	3.3	12.9
Mayo	Diesel	P116	MD3	1.3	50.6	2.9	65.3
Total Mayo Diesel				**5.0**	**110.9**	**247,010.6**	**247,148.5**
Whitehorse	Diesel	P126	WD4	41.0	87.0	16.4	44.9
Whitehorse	Diesel	P126	WD5	38.2	146.5	16.4	70.6
Whitehorse	Diesel	P126	WD6	44.1	159.6	20.0	74.0
Whitehorse	Diesel	P126	WD7	126.8	441.2	47.2	176.4
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
Total Whitehorse Diesel				**250.1**	**4,308.5**	**100.0**	**2,354.4**
Whitehorse	LNG	WG0	WG1	891.0	4,658.0	262.0	1,189.0
Whitehorse	LNG	WG0	WG2	1,367.9	4,458.1	302.0	1,095.0
Whitehorse	LNG	WG0	WG3	1,244.0	5,616.5	322.0	1,424.0
Total Whitehorse LNG				**3,502.9**	**14,732.6**	**886.0**	**3,708.0**

		Total	Rental diesel
Whitehorse LNG		3,502.9	
Diesel		752.3	34.3
Whitehorse		250.1	0.0
Dawson		428.8	
Faro		68.4	34.3
Mayo		5.0	
Total thermal generation		4,255.2	34.3

YEC 2023/24 GRA
Nov-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	118.5	224.5	161.7	352.4
Dawson	Diesel	P158	DD2	83.6	296.3	95.1	404.3
Dawson	Diesel	P158	DD3	165.4	416.5	200.4	560.2
Dawson	Diesel	P158	DD4	160.2	530.7	127.2	505.6
Dawson	Diesel	P158	DD5	312.9	818.2	228.2	699.1
Dawson	Diesel	P158	YM1	6.3	79.8	7.3	93.0
			Total Dawson Diesel	**846.8**	**2,366.1**	**819.9**	**2,614.6**
Faro	Diesel	P131	FD1	5.1	52.3	2.4	24.8
Faro	Diesel	P131	FD7	56.7	665.3	24.2	30,012.6
Faro	Diesel	YM	YM20	0.0	307.9		179.0
Faro	Diesel	YM	YM21	0.0	149.1		82.4
Faro	Diesel	YM	YM22	0.0	149.0		87.5
Faro	Diesel	YM	YM23	0.0	443.6		249.6
Faro	Diesel	YM	YM24	0.0	134.3		82.0
Faro	Diesel	YM	YM25	0.0	433.8		244.6
Faro	Diesel	YM	YM26	0.0	348.7		196.3
			Total Faro Diesel	**61.8**	**2,684.0**	**26.6**	**31,158.8**
Mayo	Diesel	P116	MD1	5.5	58.8	-246,993.2	77.1
Mayo	Diesel	P116	MD2	3.2	10.1	4.1	17.0
Mayo	Diesel	P116	MD3	0.0	50.6	0.9	66.2
			Total Mayo Diesel	**8.6**	**119.5**	**-246,988.3**	**160.2**
Whitehorse	Diesel	P126	WD4	261.0	348.0	110.2	155.0
Whitehorse	Diesel	P126	WD5	212.3	358.8	88.3	158.8
Whitehorse	Diesel	P126	WD6	195.7	355.3	85.0	159.0
Whitehorse	Diesel	P126	WD7	291.9	733.1	100.8	277.2
Whitehorse	Diesel	YM	YM10	0.0	365.2		211.7
Whitehorse	Diesel	YM	YM11	0.0	339.6		194.9
Whitehorse	Diesel	YM	YM12	0.0	322.5		187.8
Whitehorse	Diesel	YM	YM13	0.0	358.5		208.0
Whitehorse	Diesel	YM	YM14	0.0	376.1		213.9
Whitehorse	Diesel	YM	YM15	0.0	211.6		119.9
Whitehorse	Diesel	YM	YM16	0.0	449.6		252.8
Whitehorse	Diesel	YM	YM17	0.0	248.8		141.3
Whitehorse	Diesel	YM	YM18	0.0	424.3		247.0
Whitehorse	Diesel	YM	YM19	0.0	378.0		211.3
			Total Whitehorse Diesel	**960.9**	**5,269.4**	**384.2**	**2,738.6**
Whitehorse	LNG	WG0	WG1	1,869.2	6,527.2		1,189.0
Whitehorse	LNG	WG0	WG2	1,724.9	6,183.0	417.0	1,512.0
Whitehorse	LNG	WG0	WG3	1,871.7	7,488.2	457.0	1,881.0
			Total Whitehorse LNG	**5,465.8**	**20,198.4**	**874.0**	**4,582.0**

		Total	Rental diesel
Whitehorse LNG		5,465.8	
Diesel		1,878.2	0.0
Whitehorse		960.9	0.0
Dawson		846.8	
Faro		61.8	0.0
Mayo		8.6	
Total thermal generation		7,344.0	0.0

YEC 2023/24 GRA
Dec-22 YUB-YEC-1-48 Attachment 3

Location	Type	Plant	Unit	MWh	MWh YTD	HRS	HRS YTD
Dawson	Diesel	P158	DD1	47.4	272.0	74.2	426.6
Dawson	Diesel	P158	DD2	89.0	385.3	111.9	516.2
Dawson	Diesel	P158	DD3	93.3	509.8	115.7	675.9
Dawson	Diesel	P158	DD4	144.4	675.1	318.7	824.3
Dawson	Diesel	P158	DD5	183.0	1,001.2	140.3	839.4
Dawson	Diesel	P158	YM1	14.7	94.5	16.5	109.5
		Total Dawson Diesel		**571.7**	**2,937.8**	**777.3**	**3,391.9**
Faro	Diesel	P131	FD1	6.6	58.9	2.8	27.6
Faro	Diesel	P131	FD7	234.8	858.0	104.9	30,117.5
Faro	Diesel	YM	YM20	371.4	679.3	205.2	384.2
Faro	Diesel	YM	YM21	288.2	437.3	182.2	264.6
Faro	Diesel	YM	YM22	192.4	341.4	122.1	209.6
Faro	Diesel	YM	YM23	416.6	860.2	230.8	480.4
Faro	Diesel	YM	YM24	162.9	297.2	96.6	178.6
Faro	Diesel	YM	YM25	1,564.2	1,998.0	1,522.9	1,767.5
Faro	Diesel	YM	YM26	397.6	746.2	220.6	416.9
		Total Faro Diesel		**3,634.6**	**6,276.6**	**2,688.1**	**33,846.9**
Mayo	Diesel	P116	MD1	27.1	85.9	36.8	113.9
Mayo	Diesel	P116	MD2	24.8	34.9	34.4	51.3
Mayo	Diesel	P116	MD3	12.6	63.2	20.0	86.2
		Total Mayo Diesel		**64.5**	**184.0**	**91.1**	**251.4**
Whitehorse	Diesel	P126	WD4	76.5	413.0	36.2	191.2
Whitehorse	Diesel	P126	WD5	78.7	426.0	33.1	191.9
Whitehorse	Diesel	P126	WD6	71.7	415.5	31.0	190.0
Whitehorse	Diesel	P126	WD7	60.2	781.8	40.0	317.2
Whitehorse	Diesel	YM	YM10	376.4	741.6	214.8	426.5
Whitehorse	Diesel	YM	YM11	286.7	626.3	218.2	413.1
Whitehorse	Diesel	YM	YM12	166.7	489.2	99.0	286.8
Whitehorse	Diesel	YM	YM13	311.2	669.7	175.9	383.9
Whitehorse	Diesel	YM	YM14	391.5	767.6	216.2	430.1
Whitehorse	Diesel	YM	YM15	233.1	444.6	132.1	252.0
Whitehorse	Diesel	YM	YM16	338.7	788.3	189.9	442.7
Whitehorse	Diesel	YM	YM17	318.9	567.6	176.8	318.1
Whitehorse	Diesel	YM	YM18	312.9	737.2	179.6	426.6
Whitehorse	Diesel	YM	YM19	112.5	490.6	64.0	275.3
		Total Whitehorse Diesel		**3,135.7**	**8,359.1**	**1,806.8**	**4,545.4**
Whitehorse	LNG	WG0	WG1	1,630.9	8,158.1	853.0	2,042.0
Whitehorse	LNG	WG0	WG2	1,511.8	7,694.8	374.0	1,886.0
Whitehorse	LNG	WG0	WG3	2,211.2	9,699.4	539.0	2,420.0
		Total Whitehorse LNG		**5,353.9**	**25,552.3**	**1,766.0**	**6,348.0**

		Total	Rental diesel
Whitehorse LNG		5,353.9	
Diesel		7,406.5	6,241.8
Whitehorse		3,135.7	2,848.6
Dawson		571.7	
Faro		3,634.6	3,393.3
Mayo		64.5	
Total thermal generation		12,760.4	6,241.8

YEC 2023/24 GRA
YUB-YEC-1-48 Attachment 4

2021

Fuel 000 Litres	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	62.3	178.0	14.5	41.0	1.1	1.4	2.4	3.8	16.5	103.5	13.4	187.3	625.2
Mayo	0.4	11.0	1.1	0.5	0.5	0.7	0.3	0.5	1.2	0.7	3.8	0.4	21.2
Dawson	7.5	59.0	2.3	2.5	2.3	2.8	40.7	119.9	7.4	10.4	111.8	95.0	461.7
Whitehorse-Diesel	341.1	1,239.1	132.0	166.4	3.0	0.0	-0.1	3.0	18.3	17.2	271.4	1,644.2	3,835.7
Whitehorse-LNG	1,485.7	1,809.3	129.6	89.7	244.4	0.2	-0.1	0.3	93.8	143.9	1,738.9	2,543.3	8,279.1
Total	1,897.0	3,296.6	279.5	300.2	251.3	5.2	43.2	127.5	137.3	275.8	2,139.3	4,470.2	13,222.9

Thermal Generation (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	143.9	647.4	20.0	216.2	3.4	11.7	3.6	13.8	22.0	247.7	66.4	811.6	2,207.9
Mayo	2.4	42.6	2.7	2.5	2.5	2.3	1.5	1.5	2.7	2.7	12.6	1.3	77.3
Dawson	82.9	221.3	5.0	7.0	8.5	10.3	148.0	459.7	30.2	40.7	426.0	358.8	1,798.2
Whitehorse-Diesel	1,288.9	4,542.7	547.0	683.3	13.5	0.0	0.0	6.9	-5.9	113.3	1,748.7	5,566.5	14,505.0
Whitehorse- LNG	3,486.9	5,225.2	306.8	258.2	573.0	0.0	0.0	0.0	255.3	338.5	4,266.0	6,835.5	21,545.4
Total	5,005.0	10,679.2	881.6	1,167.3	600.9	24.3	153.1	481.9	304.3	742.9	6,519.7	13,573.6	40,133.8

Efficiency, KWh/l	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	2.31	3.64	1.38	5.27	3.00	8.42	1.46	3.68	1.33	2.39	4.97	4.33	3.53
Mayo	5.65	3.86	2.51	4.72	4.93	3.16	5.59	2.93	2.24	3.78	3.33	3.34	3.65
Dawson	11.07	3.75	2.17	2.78	3.70	3.63	3.64	3.83	4.09	3.90	3.81	3.78	3.90
Whitehorse-Diesel	3.78	3.67	4.14	4.11	4.50	0.00	0.00	2.31	-0.32	6.58	6.44	3.39	3.78
Whitehorse-LNG	2.35	2.89	2.37	2.88	2.34	0.00	0.00	0.00	2.72	2.35	2.45	2.69	2.60

YEC 2023/24 GRA
YUB-YEC-1-48 Attachment 4

2022

Fuel 000 Litres	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	407.5	120.7	29.2	0.6	-2.3	0.9	1.8	6.2	125.2	26.7	45.2	645.8	1,407.5
Mayo	21.1	0.4	0.4	0.9	0.7	1.0	0.0	1.7	1.4	1.1	1.7	21.7	51.9
Dawson	169.9	68.0	5.3	9.9	5.8	3.7	6.6	13.3	11.3	113.6	223.7	150.1	781.1
Whitehorse-Diesel	975.0	62.3	2.0	20.9	1.0	11.0	15.0	10.4	2.0	66.7	270.8	871.9	2,308.9
Whitehorse-LNG	1,961.8	976.0	561.3	279.6	90.5	23.1	163.7	102.3	122.2	1,410.3	2,232.5	2,281.4	10,204.7
Total	3,535.2	1,227.4	598.1	311.9	95.7	39.6	187.1	133.9	262.1	1,618.3	2,773.8	3,970.8	14,754.0

Thermal Generation (MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	1,493.7	494.6	115.1	3.9	4.2	4.4	4.0	11.9	421.9	68.4	61.8	3,634.6	6,318.6
Mayo	85.7	1.3	1.7	2.5	1.1	5.0	0.6	5.7	2.3	5.0	8.6	64.5	184.0
Dawson	643.5	245.1	19.9	36.6	21.5	12.4	23.6	48.6	39.3	428.8	846.8	571.7	2,937.8
Whitehorse-Diesel	3,373.4	455.8	21.1	72.4	8.8	36.1	53.1	35.4	2.4	250.1	960.9	3,135.9	8,405.3
Whitehorse- LNG	5,124.2	2,793.7	1,489.1	734.3	220.7	52.4	363.0	282.1	170.2	3,502.9	5,465.8	5,353.9	25,552.3
Total	10,720.4	3,990.5	1,646.9	849.7	256.3	110.4	444.3	383.7	636.1	4,255.2	7,344.0	12,760.6	43,398.0

Efficiency, KWh/l	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Faro	3.67	4.10	3.95	6.11	-1.84	4.83	2.27	1.92	3.37	2.56	1.37	5.63	4.49
Mayo	4.07	3.19	4.38	2.95	1.60	5.02		3.38	1.64	4.46	5.07	2.97	3.54
Dawson	3.79	3.60	3.78	3.69	3.71	3.40	3.56	3.66	3.48	3.78	3.79	3.81	3.76
Whitehorse-Diesel	3.46	7.31	10.55	3.46	8.82	3.29	3.54	3.41	1.18	3.75	3.55	3.60	3.64
Whitehorse-LNG	2.61	2.86	2.65	2.63	2.44	2.27	2.22	2.76	1.39	2.48	2.45	2.35	2.50

REFERENCE: **Application PDF pages 65 and 94, footnote 2**

ISSUE: Rented diesels

QUOTE: PDF page 65:

Forecast mobile diesel costs are based on negotiated contracts with the vendor and reflect both the increased number of rental units (which have increased from 15 to 20 units as of winter 2023/24) as well as the increase in rental unit costs (average cost per rental unit has increased from $0.233 million/unit as approved in 2021 to $0.338 million/unit in 2024).

…

PDF page 94, footnote 2:

LCOC for all 2024 diesel rental costs is $216 to $252 per kW-yr assuming $186.02 average YEC rental cost per kW in year 1 with escalation in range of 3% to 4%/yr …

QUESTION:

a) How valid is the assumption of three-percent to four-percent inflation for the diesel rental units when actual diesel rental costs increased by 45 percent[1] from 2021 to 2024?

ANSWER:

(a)

The assumption is very reasonable considering the existing supplier provided a quote for the 2024-2025 season with a 4% increase from 2023-2024 prices.

[1] ($0.338 million - $0.233 million)/$0.233 million = 45 percent.

REFERENCE: **Application, PDF pages 67-68**

ISSUE: Non-fuel O&M - Transmission and Distribution – Brushing and Other Non-Labour Costs

QUOTE: Total brushing costs are forecast to decrease by $0.020 million in 2023 and 2024 from 2021 approved. Brushing activities are based on Yukon Energy's brushing policy and brushing plans. Yukon Energy has had success since establishing a regular cycle as per the policy, with an overall decrease in the number of tree caused outages and an increasingly competitive bid process. Tender packages offer much higher quality information and, along with an increase in contractor familiarity with the geography and conditions of YEC lines, has resulted in positive tender results. Significant work has also been done in developing brushing specifications to be followed by contractors as well as a guideline for brushing tender evaluation.

PREAMBLE: The Board wants to understand if YEC's brushing policy and plans have resulted in better forecasting of costs.

QUESTION:

a) In light of the positive outcomes YEC submits to have obtained since establishing a brushing policy and regular cycle of brushing, please explain why 2022 actual brushing costs were approximately 10 percent[1] less than those incurred in 2021.

b) Based on the 2022 actual brushing activities and related costs, on what basis does YEC consider that it will be able to increase its brushing activities and related costs by approximately 16 percent in the year 2023?[2]

c) Please explain in more detail how the "allocation of labour costs and other non-labour costs between transmission and distribution is impacted by the allocation of the department's administrative costs", as noted on PDF page 67.

[1] Calculated as ($1.313 million (2021) less $1.180 million (2022)) divided by $1.313 million.
[2] Calculated as $1.368 million (2023) less $1.180 million (2022) divided by $1.180 million.

d) Considering the response to part (c), please explain why both transmission and distribution of? other non-labour costs increased in 2022 actual costs as compared to 2021 actual costs.

ANSWER:

(a) and (b)

The decrease in spending during 2022 was due to challenges in completing the work. Wildfires, contractor availability, and mechanical breakdowns all negatively impacted the completion of the planned scope of brushing work. These issues were not experienced to the same extent during 2023.

(c) and (d)

The transmission and distribution department annually incurs administrative costs primarily consisting of helicopter rentals to scan the lines for the purpose of identifying issue areas. These administrative costs are allocated to Transmission or Distribution on Table 3.6.1 based on the proportion of non-administrative work of each category of transmission and distribution.

The administrative costs are not a factor in the reason for increased other non-labour costs in 2022 as compared to 2021 actual costs. In addition to Brushing, the T&D Department is responsible for other costs, including:

- Distribution
  - Street light maintenance
  - Pole inspections and audits
  - Pole straightening
  - Planned repairs
  - Unplanned repairs
  - System operations
  - Outage response

- Transmission
  - Pole straightening
  - Planned repairs/maintenance

- Unplanned repairs
- System operations
- Outage response

The majority of the T&D cost is focused on Brushing, however, the overall T&D budget is relatively constant. As stated in response (a) above, less Brushing work was completed in 2022, and this allowed more budget to be allocated to these other non-brushing activities.

REFERENCE: **Application, PDF page 69**

ISSUE: Non-fuel O&M – General Operating and Maintenance costs

QUESTION:

a) Please provide a variance explanation for the increase in 2022 actual transportation costs of $0.630 million compared to 2021 actual transportation costs of $0.521 million.

b) Are the reasons provided in response to part (a) expected to continue into 2023 and 2024? If not, please explain.

c) Please explain why the costs for maintenance of company-owned properties is forecast to decrease in the years 2023 ($0.569 million) and 2024 ($0.466 million) compared to 2022 actual costs of $0.630 million.

d) Please provide a variance explanation for the decrease in 2022 actual SCADA communication costs of $0.082 million compared to 2021 actual SCADA communication costs of $0.167 million.

e) Are the reasons provided in response to part (d) expected to continue into 2023 and 2024? If not, please explain.

ANSWER:

(a)

Costs incurred in one year do not necessarily imply what costs should be in a prior or future year as costs in any particular year can vary for several reasons.

The transportation costs increased in 2022 as compared to 2021 due to the change in fuel prices. According to Statistics Canada, the average price per litre for gasoline was $1.45 in 2021 and $1.87 in 2022.

(b)

Yes, based on updated assumptions. Transportation fuel costs are forecast using a four-five-year average of litres consumed (based on average of kilometres driven and fuel efficiency) multiplied by the most recent fuel price. The price of gasoline at the time of Application preparation was $1.85/litre.

(c)

The most significant change is due to the accounting treatment for new property leases. New property leases meet the accounting definition requiring them to be capitalized. Therefore, the costs are being transferred out of Maintenance of Company Owned Properties expense to Right of Use Assets depreciation.

(d)

Costs incurred in one year do not necessarily imply what costs should be in a prior or future year as costs in any particular year can vary for several reasons.

In 2021, YEC had to replace battery modules on UPS's (Uninterrupted Power Supplies). Additionally in 2021, the satellite network, backup SCADA communications, and camera programs were progressing, and YEC purchased parts and materials for these programs.

(e)

As 2023 progresses, YEC is finding the resource needs of the IPP program, particularly communications tech resources, has slowed spending on SCADA Communication; there appears to be a shift from SCADA Communications costs to IPP program costs. The 2024 costs are forecast to increase due to requirements to replace UPS batteries, planned work (including contractor support) on satellite network and backup SCADA communications programs, and contractor support is anticipated for radio sites and the power line carrier system.

REFERENCE: **Application, PDF pages 69-71**

ISSUE: Non-fuel O&M – Administration

QUESTION:

a) Please explain why 2021 actual Environmental Management costs of $0.392 million were less than 2021 approved costs of $0.535 million and continued to be less in 2022 with actual costs of $0.329 million, notwithstanding that Environmental Management costs were "forecast to increase by $0.297 million (124%) in 2021 over 2018 approved due to increased environmental monitoring activities associated with the new three-year water license of the Aishihik Generating Station"4 in this Application.

b) Considering the response to part (a) and YEC's forecast increases for the 2023 and 2024 test years — $0.819 million and $0.798 million respectively — being due to "increased environmental monitoring activities primarily associated with the renewal of the water licence for the Aishihik Generating Station," please explain the basis on which the forecast increases, which are similar to the increases forecast previously, will come to fruition in 2023 and 2024.

c) For Recruitment costs, please provide variance explanations for the lower 2021 actual costs of $0.149 million compared to 2022 actual costs of $0.554 million.

d) Please explain the increase in forecast 2023 Contracting costs of $0.058 million in comparison to 2022 actual of $0.008 million and 2024 forecast of $0.018 million.

ANSWER:

(a)

Environmental Management costs vary on an annual basis largely based on studies and ecosystem monitoring components that change from year to year. For example, a monitoring activity may only be completed once every other year, or once every five years. Changes to monitoring frequency and timing can be made in response to direction from Regulators and others as well as in response to monitoring results that are generated between the time the forecasts are made the year prior and the time they are previously scheduled to occur. In other cases, forecasts are based on expectations for environmental

or operational conditions that do not arise in the year after they are initially forecast (i.e., the subject year's budget forecast is made 6-18 months before an expense may be incurred). For example, in the case of 2021, Yukon Energy had forecasted environmental monitoring costs associated with an emergency allowance to lower the low supply level on Marsh Lake in response to forecast flooding. Yukon Energy was not able to reach the emergency low supply level it had requested and therefore did not incur the expenses associated with environmental monitoring that would have been required if it had. Other forecast program requirements can often come in under forecast, with efficiencies found during the work related to favourable environmental conditions (e.g., unseasonable warm weather requiring fewer days to complete the work than expected) or finding a less expensive way to conduct the work (e.g., on foot vs helicopter) or otherwise costing less than anticipated for myriad of reasons. In other cases, capital project demands on the department's human resources result in some discretionary or deferrable O&M work not being completed leaving the forecast underspent. In 2022, some of the planned environmental studies and ecosystem monitoring costs associated with the Aishihik Generating Station were deemed to predominately support capital planning activities and therefore, while the work was conducted, a portion of the costs were allocated to capital projects and a portion to ongoing O&M obligations, depending on the specific scope of work.

(b)

Significant expansion of monitoring program and project authorization requirements (e.g., water use licenses, air emissions permits) have been seen recently that confirm the reasonableness of the GRA forecasts. Examples include the following:

- In the case of Aishihik, a new water use license was issued at the end of 2022 and included material increases in the requirements for studies and monitoring as compared to previous licenses.

- A new air emission permit requirement for an air quality monitoring program in Faro, which was substantively deployed in 2023 has also driven up annual O&M Environment Program costs.

- In the case of Faro air emission monitoring, the expectation was that the program would be up and running in 2022 but delays in system design and procurement bumped the substantive monitoring station construction costs to 2023.

The 2023 forecast includes:

- An increase of approximately $0.400 million to $0.550 million for the Aishihik Generating Station Annual Ecological and Downstream Monitoring Program.

- An increase of $0.025 million to $0.100 million for the Mayo Generating Station Annual Ecological Monitoring.

- An increase of $0.085 million to $0.100 million for Faro Air/Noise Monitoring.

(c)

Recruiting costs include relocation costs. These costs can vary from year to year based on such factors as FTE additions, turnover, timing of relocation costs, what positions are being replaced and where new employees are sourced from. In general, recruiting and relocation costs were limited in 2021 due to the Covid-19 pandemic. In comparing 2022 to 2021, there were more FTE additions in 2022, a higher turnover rate and more relocations from out of territory. There was more recruitment at the senior level, which is more expensive due to the use of external recruiting agencies. In 2022, costs included recruiting of the VP Operations, VP Engineering and the Director of People & Culture.

(d)

The forecast 2023 Contracting costs are $0.050 million greater than 2022 actual due to a one-time project for assistance with developing a First Nations procurement policy/guideline ($0.040 million), as well as externally contracted procurement services ($0.010 million). The externally contracted procurement services are forecast to continue in 2024.

REFERENCE: **Application, PDF pages 71-74**

ISSUE: Non-fuel O&M - Insurance and Reserve for Injuries and Damages

QUESTION:

a) Please provide any analysis or evidence to support YEC's statement that "the market rate increases experienced by YEC as part of the 2023 renewals are consistent with peer utilities in Canada." In the response, please identify the peer utilities being used in the analysis provided.

b) Please explain what the reduced "participation rate of an insurer on our property program" is in reference to.

c) Please identify the dollar value change in "deductible on our property policy to limit the rate increase caused by market conditions and recent claims" and the savings that resulted.

d) Referring to Table 3.11: RFID Annual Charges Ten Year History, please explain why the actual annual charges identified on that schedule for the years 2021 and 2022 do not correspond to the annual costs shown on Table 3.11.1: RFID Continuity Schedule for those same years.

e) Please provide details of the actual annual charges for the years 2021 and 2022 as shown on Table 3.11.1: RFID Continuity Schedule.

ANSWER:

(a)

The basis for YEC's statement that "the market rate increases experienced by YEC as part of the 2023 renewals are consistent with peer utilities in Canada" is explained below.

Yukon Energy participates in the Canadian Electrical Risk Managers group which is comprised of Risk Managers from approximately 25 utilities across Canada. Members share detailed information on insurance renewal results, challenges, and general risk management practices. The information obtained through membership in this peer group

is helpful in confirming market observations provided by YEC's insurance broker and provided the basis for the above statement, however the specific information is shared in confidence and not to be released externally.

(b)

The reference to the reduced "participation rate of an insurer in our property program" is explained below.

YEC purchases a limit of $400M on its property insurance policy. This coverage is provided by a number of insurers who all take a pro-rated share of the premiums paid and are responsible for the same share of any claims. For the 2023-24 policy period, there are nine insurers on the program with participation rates ranging from 2.5% to 25%. During the renewal process, one insurer required a higher premium increase than the others. By reducing the participation rate of that insurer, a lower overall premium increase was achieved.

(c)

In 2021, YEC increased the deductible on our property policy from $500k to $1M which resulted in premium savings of $175k.

(d)

The annual costs in Table 3.11.1 represents RFID projects completed and closed within the year, whereas Table 3.11 represents project costs within a year, whether or not the project was in WIP at the beginning or end of the year.

(e)

The question is asking for "actual annual charges" on Table 3.11.1, but "actual annual charges" are on Table 3.11 while Table 3.11.1 represents only RFID projects completed and closed within the year. YEC in this response, is assuming the YUB is asking for details of "actual annual charges" as shown in Table 3.11, whether or not the projects were in WIP at the beginning or end of the year.

Actual annual charges on Table 3.11 include:

	2021	2022
Alexco Mill Tap Leaning Pole	$ 16	$ -
S253-52-1 Breaker Failure	37	-
2021 Flood Emergency Response	850	-
WG2 Failure	(282)	-
WG1 Stator Repair	190	-
Covid-19 Incremental (write-off in 2022)	30	(104)
WH1&2 Penstock Failure	76	-
Gearbox for WG2 Failure	-	292
L177 Outages	-	114
S248 52-1 PRDs Failure	-	50
DD1 Coupling Failure	-	290
L174 - Crystal Creek Fire	-	86
2022 Flood Mitigation Lewes	-	219
Flood Mitigation for Aishihik	-	33
WG2 Low Methane Content Issues	-	139
VP700 LNG Vaporizer Leak	-	13
MH0 Rock Slope Failure	-	346
	$ 917	$ 1,478

1

REFERENCE: **Application PDF page 77, Table 3.14; PDF pages 500-501, Tab 7, Schedule 3B, pages 7-11 and 7-12**

ISSUE: Amortization of deferred charges

QUOTE: Application, PDF page 77:

Forecast amortization of deferred charges is $3.657 million in 2023 and $5.594 million in 2024, compared to $5.608 million for 2021 approved. This 2024 amount includes amortization of feasibility and relicensing costs ($3.195 million) amortization of regulatory costs ($0.846 million, including $0.250 million hearing reserve annual appropriation), intangibles ($1.281 million), dam safety costs ($0.051 million) and amortization of vegetation management deferral costs ($0.222 million).

PREAMBLE: The Board requires further clarification of the components of the total amortization of deferred charges in Table 3.14 for the years 2021 to 2024 and an explanation of YEC's method for the calculation of contribution amortization.

QUESTION:

a) Please provide a list, including subtotals where required, to illustrate the 2021-22 actual and 2023-24 forecast amortization of deferred charges by cost category.

b) For the years 2023 and 2024, please ensure that the list provided in response to part (a) reflects the amounts calculated as amortization expense for deferred costs and intangibles as summarized on Tab 7, Schedule 3B (page 7-11 for 2023 and 7-12 for 2024). Otherwise, provide a reconciliation between the cost categories used in the Table 3.14 amounts and the Schedule 3B amounts.

c) Please provide a reference to where the amortization of contributions shown on Table 3.14 for the years 2021 to 2024 is determined in this Application. Otherwise, provide an explanation and the calculation in response to this IR.

ANSWER:

(a) to (c)

The following table shows the reconciliation of amortization expenses of deferred costs in Table 3.14 and Schedule 3B. Please see YUB-YEC-1-54 Attachment 1 for details for 2021 and 2022 actuals, and 2023 and 2024 forecasts.

	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Amortization of deferred charges Table 3.14	5,529	3,886	3,657	5,594
Amortization of deferred charges Schedule 3B	3,842	2,965	2,959	4,913
Feasibility Studies	2,168	1,491	1,049	2,268
Relicensing	339	339	820	928
Dam Safety	55	51	51	51
Intangibles	866	789	718	1,281
Regulatory	414	295	321	386
Variance	-1,687	-921	-698	-681
Variance Details	1,687	921	698	681
Contributions				
WTE Contributions	166	166	7	
SKTP Planning Project Contributions	678	169		
Atlin Storage Contributions	223			
Geothermal Contributions	195			
Biogas Preliminary Design 2	0			
EV Technical Study	0			
LNG Transportation Options	3			
LNG Feasibility Study	30			
DSM Contributions	94	94	220	210
Victoria Gold PPA Contributions	20	20		
Resource Plan Update Contribution	1			
Vegetation Management Deferral [not shown in Schedule 3B]	222	222	222	222
Hearing Reserve [not shown in Schedule 3B]	55	250	250	250

YUB-YEC-1-54
Attachment 1

Deferred Cost Amortization Reconciliation

($000)

	Actual 2021	Actual 2022	Proposed 2023	Proposed 2024
Amortization of deferred charges Table 3.14	5,529	3,886	3,657	5,594
Amortization of deferred charges Schedule 3B	3,842	2,965	2,959	4,913
Feasibility Studies	2,168	1,491	1,049	2,268
Relicensing	339	339	820	928
Dam Safety	55	51	51	51
Intangibles	866	789	718	1,281
Regulatory	414	295	321	386
Variance	-1,687	-921	-698	-681
Variance Details	1,687	921	698	681
Contributions				
WTE Contributions	166	166	7	
SKTP Planning Project Contributions	678	169		
Atlin Storage Contributions	223			
Geothermal Contributions	195			
Biogas Preliminary Design 2	0			
EV Technical Study	0			
LNG Transportation Options	3			
LNG Feasibility Study	30			
DSM Contributions	94	94	220	210
Victoria Gold PPA Contributions	20	20		
Resource Plan Update Contribution	1			
Vegetation Management Deferral [not shown in Schedule 3B]	222	222	222	222
Hearing Reserve [not shown in Schedule 3B]	55	250	250	250

YUKON ENERGY CORPORATION Schedule 3B - 2021

Calculation of Amortization Expense for Deferred Costs and Intangibles (2021)

$000

	Total Expenditures					
	Dec 31 2020	2021 Additions	2021 Transfers /Retired	Dec 31 2021	Amortization Rate and Method	2021 Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Atlin Storage	2,231		(2,231)		SL-10 years	223
Geothermal	1,947		(1,947)		SL-10 years	195
Waste To Energy	1,667			1,667	SL-10 years	167
Mayo Power Plant Assessment	95		(95)		SL-5 years	13
EV Technical Study	68		(68)		SL-5 years	5
Biogas Preliminary Design 2	72		(72)		SL-5 years	1
Home Heating Retrofit Options	10		(10)		SL-5 years	1
LNG Boil Off Gas Options	46		(46)		SL-5 years	9
Dawson DT Distribution Fusing	4		(4)		SL-5 years	1
Upper Pelly - Large Hydro	291		(291)		SL-5 years	58
Ferry Hill Wind Feasibility Study	119		(119)		SL-5 years	24
Condition Assessment of Selected Assests	231		(231)		SL-5 years	46
Aishihik Turbine Re-running	116		(116)		SL-5 years	23
Whitehorse Diesel Plant Conven	319		(319)		SL-5 years	64
Enterprise Risk Management	169		(169)		SL-5 years	34
Building Condition Report 2015	104		(104)		SL-5 years	21
Assets Condition Assessment of WH&WD	228		(228)		SL-5 years	46
Life Cycle Analysis LNG/Diesel	118		(118)		SL-5 years	24
LNG Transportation Options	278		(278)		SL-5 years	56
L170/L178 Crossarm Investigation	190		(190)		SL-5 years	38
Transformer T9 Assessment	105		(105)		SL-5 years	21
Condition Assmnt of YEC Assets	128		(128)		SL-5 years	26
LNG Supply Option	273		(273)		SL-5 years	55
Climate Change Study	604			604	SL-5 years	121
Whitehorse Hydro Turbine Re-runnering	164			164	SL-5 years	33
SKTP Planning Project 2015-2017	3,390			3,390	SL-5 years	678
Resource Plan Update 2016	2,015			2,015	SL-5 years	403
Vegatation Mgt on Powerline Right of Way	47			47	SL-5 years	9
Moon Lake Hydro Project	171			171	SL-5 years	34
LNG Third Engine Assessment	47			47	SL-5 years	9
Asset Management Plan	418			418	SL-5 years	84
CIS Review 2017	26			26	SL-5 years	5
IFRS Upgrades for Budgeting and GRA	73			73	SL-5 years	15
Unit#4 Weir Assessement	87			87	SL-5 years	17
Diesel Generator Protection Review	34			34	SL-5 years	7
Line Inspection L170/L171/L172/L169	231			231	SL-5 years	46
Disaster Recovery Plan	4			4	SL-5 years	1
N-1 Event Risk Assessment	129			129	SL-5 years	26
Dyke Heating Pipe Assessment	68			68	SL-5 years	14
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	3
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	3
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks		90		90	SL-5 years	10
FD7 Condition Assessment		73		73	SL-5 years	2
Wareham Spillgate Leakage Reduction		53		53	SL-5 years	-
P125 Intake Trash Rack Cleaning System		59		59	SL-5 years	-
PMF Flood Study		78		78	SL-5 years	4
IPP SOP Implentation		326		326	SL-5 years	-
WTE Contributions	(1,397)			(1,397)	SL-5 years	(166)
Atlin Storage Contributions	(1,338)		1,338	-		(223)
Geothermal Contributions	(1,168)		1,168	-		(195)
Biogas Preliminary Design 2	(17)		17	-		(0)
EV Technical Study	(4)		4	-		(0)
LNG Transportation Options	(15)		15	-		(3)
LNG Feasibility Study	(150)		150	-		(30)
SKTP Planning Project Contributions	(3,390)		3,390	-		(678)
Total Feasibility Study Closed	15,087	678	(1,060)	14,706		2,168

YUKON ENERGY CORPORATION Schedule 3B - 2021

Calculation of Amortization Expense for Deferred Costs and Intangibles (2021)

$000

	Total Expenditures					
	Dec 31 2020	2021 Additions	2021 Transfers /Retired	Dec 31 2021	Amortization Rate and Method	2021 Expenses
Regulatory						
Completed Projects:						
DSM	1,883			1,883	SL-10 years	187
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
Asset Appraisal-Replace Cost	47			47	SL-5 years	9
Victoria Gold PPA	142			142	SL-5 years	28
LED Streetlight 2015/2018	261			261	SL-5 years	52
10 Year Renewable Energy Plan	634			634	SL-5 years	127
Investigate IFRS	181		(181)	-		36
Resource Plan Update	244		(244)	-		49
Arc-flash Study	179		(179)	-		36
DSM Contributions	(938)			(938)	SL-10 years	(94)
Victoria Gold PPA Contributions	(100)			(100)	SL-5 years	(20)
Resource Plan Update Contribution	(6)		6	-		(1)
Total Regulatory Closed	2,710	-	(598)	2,112		414
Relicensing						
Completed Projects:						
Aishihik 2020 3 Year Relicensing	917			917	License term	306
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	21
Mayo Relicensing	129			129	License term	11
Total Relicensing Closed	1,372	-	-	1,372		339
Dam Safety Review						
Completed projects	148	254	(148)	254	SL-5 years	55
Total Deferred Costs	**19,317**	**933**	**-1,806**	**18,444**		**2,976**
Intangibles						
Completed Projects:						
Software Costs	1,645	174	(516)	1,303	SL-5 years	237
Financial Software Costs	2,836	4,550		7,386	SL-10 years	629
Total Intangibles Closed	4,481	4,724	(516)	8,689		866
Total Deferred and Intangibles Closed	**23,798**	**5,657**	**-2,322**	**27,133**		**3,842**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION Schedule 3B - 2022

Calculation of Amortization Expense for Deferred Costs and Intangibles (2022)

$000

	Total Expenditures					
	Dec 31	2022		Dec 31	Amortization Rate	2022
	2021	Additions	Transfers /Retired	2022	and Method	Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Waste To Energy	1,667		(1,667)	-	SL-10 years	167
Climate Change Study	604		(604)	-	SL-5 years	30
Whitehorse Hydro Turbine Re-runnering	164		(164)	-	SL-5 years	19
SKTP Planning Project 2015-2017	3,390		(3,390)	-	SL-5 years	169
Resource Plan Update 2016	2,015		(2,015)	-	SL-5 years	235
Vegatation Mgt on Powerline Right of Way	47		(47)	-	SL-5 years	7
Moon Lake Hydro Project	171		(171)	-	SL-5 years	34
LNG Third Engine Assessment	47		(47)	-	SL-5 years	9
Asset Management Plan	418		(418)	-	SL-5 years	84
CIS Review 2017	26		(26)	-	SL-5 years	5
IFRS Upgrades for Budgeting and GRA	73		(73)	-	SL-5 years	15
Unit#4 Weir Assessement	87		(87)	-	SL-5 years	17
Diesel Generator Protection Review	34		(34)	-	SL-5 years	6
Line Inspection L170/L171/L172/L169	231		(231)	-	SL-5 years	46
Disaster Recovery Plan	4			4	SL-5 years	1
N-1 Event Risk Assessment	129			129	SL-5 years	26
Dyke Heating Pipe Assessment	68			68	SL-5 years	14
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	3
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	3
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	326			326	SL-5 years	65
WH Post-Flood Assessment		115		115	SL-5 years	8
Emergency Preparedness Improvement		60		60	SL-5 years	
P126 Building Renovation		196		196	SL-5 years	
WH4 Low Water Cavitation Study & Recommendation		47		47	SL-5 years	1
WTE Contributions	(1,397)		1,115	(283)	SL-5 years	(166)
SKTP Planning Project Contributions	(3,390)		3,390	-		(169)
Total Feasibility Study Closed	11,316	418	(4,471)	7,263		1,491
Regulatory						
Completed Projects:						
DSM	1,883	1,495		3,378	SL-10 years	188
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
Asset Appraisal-Replace Cost	47			47	SL-5 years	9
Victoria Gold PPA	142			142	SL-5 years	28
LED Streetlight 2015/2018	261			261	SL-5 years	52
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(938)	(1,142)		(2,080)	SL-10 years	(94)
Victoria Gold PPA Contributions	(100)			(100)	SL-5 years	(20)
Total Regulatory Closed	2,112	353	-	2,465		295
Relicensing						
Completed Projects:						
Aishihik 2020 3 Year Relicensing	917		(805)	112	License term	306
Aishihik 2022 5 Year Relicensing		3,903		3,903	License term	-
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	21
Mayo Relicensing	129			129	License term	11
Total Relicensing Closed	1,372	3,903	(805)	4,470		339
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**15,054**	**4,675**	**-5,275**	**14,453**		**2,176**
Intangibles						
Completed Projects:						
Software Costs	1,303	278	(396)	1,185	SL-5 years	235
Financial Software Costs	7,386			7,386	SL-10 years	554
Total Intangibles Closed	8,689	278	(396)	8,572		789
Total Deferred and Intangibles Closed	**23,743**	**4,953**	**-5,671**	**23,025**		**2,965**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION Schedule 3B - 2023

Calculation of Amortization Expense for Deferred Costs and Intangibles (2023)

$000

	Total Expenditures					
	Dec 31	2023 Forecast		Dec 31	Amortization Rate	2023 Forecast
	2022	Additions	Transfers /Retired	2023	and Method	Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Disaster Recovery Plan	4			4	SL-5 years	0
N-1 Event Risk Assessment	129			129	SL-5 years	26
Dyke Heating Pipe Assessment	68			68	SL-5 years	14
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	3
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	3
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	326	70		396	SL-5 years	65
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
WTE Contributions	(283)			(283)	SL-5 years	(7)
Southern Lakes Enhanced Storage		8,784		8,784	SL-10 years	-
Public Safety Plans		225		225	SL-5 years	-
System Wide Stability Study		200		200	SL-5 years	-
System Wide Arc Flash Study		198		198	SL-5 years	-
Mayo Civil Infrastructure Refurbishment Planning		168		168	SL-5 years	-
Digital Strategy and Policy Development		120		120	SL-5 years	-
Privacy Management Program		100		100	SL-5 years	-
Vegetation Management Plan Update		225		225	SL-5 years	-
Other Projects with <$100k Spending		319		319	SL-5 years	-
Total Feasibility Study Closed	7,263	10,410	-	17,673		1,049
Regulatory						
Completed Projects:						
DSM	3,378	1,272		4,649	SL-10 years	338
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
Asset Appraisal-Replace Cost	47			47	SL-5 years	3
Victoria Gold PPA	142			142	SL-5 years	17
LED Streetlight 2015/2018	261			261	SL-5 years	52
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,080)	(22)		(2,102)	SL-10 years	(208)
Victoria Gold PPA Contributions	(100)			(100)	SL-5 years	(12)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)		386		386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)		23		23	Hearing Reserve	
Total Regulatory Closed	2,465	1,659	-	4,124		321
Relicensing						
Completed Projects:						
Aishihik 2020 3 Year Relicensing	112			112	License term	6
Aishihik 2022 5 Year Relicensing	3,903	575		4,479	License term	781
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	21
Mayo Relicensing	129			129	License term	11
Total Relicensing Closed	4,470	575	-	5,046		820
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**14,453**	**12,644**	**0**	**27,097**		**2,241**
Intangibles						
Completed Projects:						
Software Costs	1,185	441		1,627	SL-5 years	226
Financial Software Costs	7,386			7,386	SL-10 years	492
PAMMS Asset Management Framework		5,466		5,466	SL-10 years	
Total Intangibles Closed	8,572	5,907	-	14,479		718
Total Deferred and Intangibles Closed	**23,025**	**18,551**	**0**	**41,576**		**2,959**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION Schedule 3B - 2024

Calculation of Amortization Expense for Deferred Costs and Intangibles (2024) August 31, 2023

$000

	Total Expenditures					
	Dec 31	2024 Forecast		Dec 31	Amortization Rate and Method	2024 Forecast
	2023	Additions	Transfers /Retired	2024		Expenses
Feasibility Study						
Completed Projects:						
Gladstone	4,521			4,521	SL-10 years	452
Dyke Heating Pipe Assessment	68			68	SL-5 years	10
Dawson DT Distribution Upgrade	79			79	SL-5 years	16
Water Study Main Building	13			13	SL-5 years	1
BCP GAP Analysis	75			75	SL-5 years	15
Study Road Infrastructure May A&B	15			15	SL-5 years	1
Mayo & Aishihik Climate Change	667			667	SL-5 years	133
Elevator Study Aishik	6			6	SL-5 years	1
Radio Repeater Assessment	25			25	SL-5 years	5
Transmission Line Access Plan	88			88	SL-5 years	18
Mt Sumanik Wind Feasibility St	744			744	SL-5 years	149
Small Hydro Project	16			16	SL-5 years	3
Mayo Earthworks	90			90	SL-5 years	18
FD7 Condition Assessment	73			73	SL-5 years	15
Wareham Spillgate Leakage Reduction	53			53	SL-5 years	11
P125 Intake Trash Rack Cleaning System	59			59	SL-5 years	12
PMF Flood Study	78			78	SL-5 years	16
IPP SOP Implentation	396			396	SL-5 years	79
WH Post-Flood Assessment	115			115	SL-5 years	23
Emergency Preparedness Improvement	60			60	SL-5 years	12
P126 Building Renovation	196			196	SL-5 years	39
WH4 Low Water Cavitation Study & Recommendation	47			47	SL-5 years	9
Southern Lakes Enhanced Storage	8,784			8,784	SL-10 years	878
Public Safety Plans	225			225	SL-5 years	45
System Wide Stability Study	200			200	SL-5 years	40
System Wide Arc Flash Study	198			198	SL-5 years	40
Mayo Civil Infrastructure Refurbishment Planning	168			168	SL-5 years	34
Digital Strategy and Policy Development	120			120	SL-5 years	24
Privacy Management Program	100			100	SL-5 years	20
Vegetation Management Plan Update	225			225	SL-5 years	45
Cyber Security Framework		140		140	SL-5 years	
Transmission Line Detailed Inspection Program		250		250	SL-5 years	
Gates/TIV's Certification Assessment System Wide		200		200	SL-5 years	40
Digital Reporting Review		125		125	SL-5 years	
Records Policy Planning and Program Development		100		100	SL-5 years	
Breaker Condition Assessment		100		100	SL-5 years	
Other Projects with <$100k Spending	319	(10)		309	SL-5 years	64
Total Feasibility Study Closed	17,823	905	-	18,728		2,268
Regulatory						
Completed Projects:						
DSM	4,649	1,160		5,809	SL-10 years	465
YUB 2007-8 - Part 3 Hearing	185			185	SL-45 years	4
10 Year Renewable Energy Plan	634			634	SL-5 years	127
DSM Contributions	(2,102)			(2,102)	SL-10 years	(210)
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	386			386	Hearing Reserve	
GRA 2020-2021 (Hearing Reserve Acct)	23			23	Hearing Reserve	
GRA 2023-2024 (Hearing Reserve Acct)		250		250	Hearing Reserve	
Total Regulatory Closed	3,775	1,410	-	5,185		386
Relicensing						
Completed Projects:						
Aishihik 2022 5 Year Relicensing	4,479			4,479	License term	896
Whitehorse Hatchery Water Relicensing	40			40	License term	2
Whitehorse Relicensing	286			286	License term	20
Mayo Relicensing	129			129	License term	11
WRGS Thermal Assessment & Permitting		413		413	License term	
Total Relicensing Closed	4,933	413	-	5,346		928
Dam Safety Review						
Completed projects	254			254	SL-5 years	51
Total Deferred Costs	**26,786**	**2,728**	**0**	**29,514**		**3,632**
Intangibles						
Completed Projects:						
Software Costs	1,627	380		2,007	SL-5 years	279
Financial Software Costs	7,386			7,386	SL-10 years	455
PAMMS Asset Management Framework	5,466			5,466	SL-10 years	547
Total Intangibles Closed	14,479	380	-	14,859		1,281
Total Deferred and Intangibles Closed	**41,265**	**3,108**	**0**	**44,373**		**4,913**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

REFERENCE: **Application, PDF pages 79 and 80, Table 3.14-4**

ISSUE: Defined Pension Deferral Account

QUOTE: Board Order 2022-03 approved Defined Pension Deferral Account to defer any variances between approved defined benefit pension plan expense in the test year and actuals. Table 3.14.4 provides a continuity schedule for this deferral account. The addition of $0.047 million and -$0.109 million reflect the variances between the approved amount of $0.720 million included in the 2021 labour cost and actual amounts of $0.767 million for 2021 and $0.611 million for 2022. YEC is not proposing amortization of the deferral account balance at this time as the balance is not significant.

PREAMBLE: The Board requires further clarification.

QUESTION:

a) Please clarify if YEC is required to either obtain or submit an actuarial valuation of its defined pension deferral account on a regular basis to the Board.

b) If confirmed, please provide the details of the last actuarial valuation provided, as required.

ANSWER:

(a) and (b)

The deferral account was approved by Board Order 2022-03. In that Order, the Board did not direct YEC to obtain or submit an actuarial valuation of its defined pension deferral account on a regular basis to the Board.

Yukon Energy conducts periodical Pension Plan actuarial valuation reports and files with the Canada Revenue Agency (CRA). The latest actuarial valuation report was prepared for January 1, 2023 and filed with the CRA. Please see YUB-YEC-1-55 Attachment 1 for copies of the report.

July 7, 2023

Registered Plans Directorate
Canada Revenue Agency
Ottawa, ON K1A 0L5

Dear Sir/Madam,

CRA# 1041011 – Yukon Energy Corporation Employees' Pension Plan January 1, 2023 Actuarial Valuation Report

Please find enclosed a copy of the Report on the Yukon Energy Corporation Employees' Pension Plan Actuarial Valuation as at January 1, 2023.

I trust the report is satisfactory. If you have any questions, please do not hesitate to contact us.

Regards,

Rory O'Connor
Consultant, George & Bell Consulting Inc.
M2-601 West Broadway, Vancouver, BC V5Z 4C2
Tel: 604-318-7651
roconnor@georgeandbell.com

Copy: Mr. Jason Epp (w/ enc.)
Yukon Energy Corporation

George&Bell CONSULTING

July 7, 2023

Mr. Jason Epp
Chief Financial Officer
Yukon Energy Corporation
2 Miles Canyon Road
Whitehorse, YT Y1A 5L6

Yukon Energy Corporation Employees' Pension Plan
Actuarial Valuation as at January 1, 2023

Dear Jason:

We are pleased to present the final report on the actuarial valuation for funding purposes as at January 1, 2023 for the Plan. This letter summarizes the highlights of the report and provides other important information. A summary of the key valuation results is as follows:

1. The Plan is fully funded on going-concern basis. The actuarial value of assets exceeds the actuarial liability by $1,877,700. The funded ratio is 109.1%.
2. The Plan has a solvency excess of $3,226,200 and a solvency ratio of 117.8%.. The average solvency ratio reflecting this, and the previous two valuations, is 109.3%.
3. Company contributions are required monthly at a rate of:

   815% of employee contributions

   to satisfy the minimum funding requirements under pension legislation until the date of the next actuarial valuation, which will be conducted at January 1, 2024. Please refer to the Contribution Adjustment section below.

The report presents a detailed development of the assets and liabilities of the Plan. A copy of the report was filed on June 29, 2023 with the Office of the Superintendent of Financial Institutions and the Canada Revenue Agency on the Company's behalf.

It should be noted that this letter is only a summary and should not be used in lieu of the report; please read the report and retain it for your records.

Contribution Adjustment

The above noted minimum Company contributions are effective January 1, 2023. The Company has been contributing at a higher rate than the above requirement for 2023 year-to-date. Furthermore, as the Company is no longer required to make special payments in respect of an unfunded liability or a solvency deficiency, the Company is not permitted to make contributions in excess of the minimum contribution requirements. The Company must cease to make the minimum Company contributions until the over-contribution has been corrected.

Based on total employee contributions reported up to and including June 2023 of $10,827.61 in respect of 2023, total employer required contributions in 2023 year-to-date are $88,245.02. As the Company has contributed $149,343.14 in respect of 2023 year-to-date, the Company has overcontributed by $61,098.11. Therefore, we recommend that Company contributions cease until an additional total of $7,496.70 in employee contributions is remitted to the Plan, or until employee contributions for 2023 total $18,324.31. Employer contributions should then resume at 815% of employee contributions as noted above.

If employee contributions in 2023 are less than $18,324.31 due to members retiring earlier than expected, then employer contributions will resume in 2024 after sufficient employee contributions have been made. We will provide direction in late 2023/early 2024 if this is necessary.

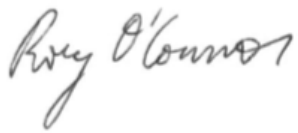
Actuarial Assumptions for Administration Purposes

Under the terms of the Plan, the assumptions used for administration purposes (such as actuarial equivalent reductions, optional forms of pension, or conversion of flex-contributions) are as adopted by the Company on the advice of the Actuary. To keep these assumptions consistent with the January 1, 2023 actuarial valuation report, we recommend that the Company adopt the assumptions outlined in the attached exhibit effective July 1, 2023.

If you agree with our recommended assumptions, please complete the certification section of the attached exhibit and return it to us for our records.

We trust that you find the foregoing and enclosed to be in order. Should you have any questions, please do not hesitate to contact us.

Sincerely,



Rory O'Connor
Consultant
George & Bell Consulting Inc.
604-318-7651
roconnor@georgeandbell.com

Enc.

George&Bell CONSULTING

Exhibit – Administration Assumption Recommendation

Under the terms of the Plan, the assumptions used for administration purposes (such as actuarial equivalent reductions, optional forms of pension, or conversion of flex-contributions) are as adopted by the Company on the advice of the Actuary. To keep these assumptions consistent with the January 1, 2023 actuarial valuation report, we recommend that the Company adopt the assumptions outlined below effective July 1, 2023.

Assumptions	Old Assumptions	New Assumptions
Discount rate	4.4% per year	5.4% per year
Mortality	CPM2014 Private table projected using Scale MI-2017	CPM2014 Private table projected using Scale MI-2017
Unisex ratio	95% male / 5% female	95% male / 5% female
Pension indexation rate	2.0% per year	2.0% per year

CERTIFICATION

Yukon Energy Corporation hereby adopts the above new assumptions for administration purposes effective July 1, 2023.

Date

Authorized Signatory

George&Bell CONSULTING

Yukon Energy Corporation Employees' Pension Plan

Actuarial Valuation as at January 1, 2023

Registration Numbers: OSFI 56997
CRA 1041011

June 29, 2023

Vancouver Office
M2-601 West Broadway
Vancouver BC V5Z 4C2
888-800-1450

georgeandbell.com

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1. Executive Summary

Below we have provided an overview of the valuation's results and key assumptions. The next actuarial valuation should be conducted no later than January 1, 2024.

Going Concern Funded Status	January 1, 2022 $	January 1, 2023 $
Going concern assets	21,873,100	22,547,500
Going concern liabilities	23,068,000	20,669,800
Actuarial excess (unfunded liability)	(1,194,900)	1,877,700
Funded ratio	94.8%	109.1%

Solvency Funded Status	January 1, 2022 $	January 1, 2023 $
Solvency assets	24,021,300	21,301,600
Solvency liabilities	22,230,900	18,075,400
Solvency assets less solvency liabilities	1,790,400	3,226,200
Solvency ratio	108.1%	117.8%

Employer Contribution Requirements	January 1, 2022 Annual $	January 1, 2023 Annual $
Current service cost (including non-investment expense)	343,700	247,800
Special payments	123,900	0
Total minimum required	467,600	247,800

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Going Concern Key Assumptions	January 1, 2022	January 1, 2023
Discount rate	4.4% per year	5.4% per year
Salary increases	3.1% per year	3.1% per year
Inflation rate	2.0% per year	2.0% per year
Retirement	Retire when age plus service reaches 90 points, but no later than age 65	Retire when age plus service reaches 90 points, but no later than age 65 Active members past 90 points or age 65 assumed to retire one year after the valuation date.
Mortality (post-retirement only)	CPM2014 Private table projected using Scale MI-2017	CPM2014 Private table projected using Scale MI-2017

Solvency Key Assumptions	January 1, 2022	January 1, 2023
Discount rate	Transfers: 2.1% for 10 years, 3.1% thereafter; Annuity: 2.9%	Transfers: 4.3% for 10 years, 4.7% thereafter; Annuity: 4.9%
Retirement	**Annuity Purchase:** Best age if over age 55 or with 90 points, deferred to 65 otherwise **Lump Sum Transfer:** If over age 55 or with 90 points, 50% at the best age and 50% at the earliest unreduced age, deferred to 65 otherwise	**Annuity Purchase:** Best age if over age 55 or with 90 points, deferred to 65 otherwise **Lump Sum Transfer:** If over age 55 or with 90 points, 50% at the best age and 50% at the earliest unreduced age, deferred to 65 otherwise
Mortality	CPM2014 table projected using Scale CPM-B	CPM2014 table projected using Scale CPM-B

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2. Introduction

We have been retained by Yukon Energy Corporation (the "Employer") to conduct an actuarial valuation on the Yukon Energy Corporation Employees' Pension Plan (the "Plan") as at January 1, 2023.

The purposes of the valuation are to:

- report on the funded status of the Plan on both a going-concern and solvency basis;
- determine the minimum amount of contributions required by the Employer under the *Pension Benefits Standards Act, 1985* (the "Act");
- determine the maximum amount of Employer contributions allowed under the *Income Tax Act* (Canada) (the "ITA");
- provide information and the actuarial opinion required by the regulatory authorities.

The information contained in this report was prepared for the internal use of the Employer and for filing with the Office of the Superintendent of Financial Institutions ("OSFI") and with the Canada Revenue Agency ("CRA"), in connection with our valuation of the Plan. This report is not intended, nor suitable, for any other purposes.

All of the attached sections and exhibits are integral parts of our report.

This report and any of its content may not be distributed, published, made available or relied upon by any person other than its intended users, without the express written permission of George & Bell Consulting Inc., unless and only to the extent otherwise required by law.

Changes since the Previous Valuation

The last actuarial valuation of the Plan filed with OSFI was prepared as at January 1, 2022. Since the last actuarial valuation, the following changes have occurred:

1. All assumptions were reviewed, and some were revised based on expected future experience and changes to plan provisions, if applicable.
2. During the inter-valuation period the Employer reviewed and revised the Statement of Investment Policies and Procedures (SIPP). The latest such document was approved by the Employer on May 16, 2023 and the same was used to determine the valuation discount rate.

Details of the above changes which affect the funded status and/or future minimum required contributions of the Plan are outlined in this report.

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Terms of Engagement

Terms of our engagement for preparing this valuation included the following:

- The Employer contribution rates were determined as the minimum required to satisfy the Act.
- The smoothed market value of assets was used for the going-concern valuation, as approved by the Employer.
- The Canadian Institute of Actuaries' Standards of Practice specify that the going concern valuation use best estimate assumptions containing no deliberate margins for conservatism unless required by law or by the terms of an appropriate engagement. The assumptions, methods and use of margins were discussed at the Employer's meeting on May 16, 2023. At that meeting the going concern actuarial assumptions and methods used for this valuation were approved by the Employer and are disclosed in this report.

Subsequent Events

We have not been made aware of any subsequent events nor any extraordinary changes to the Plan, membership, or other data that would materially affect the results of this valuation.

Filings

An actuarial valuation must be filed with OSFI as at the effective date of the Plan and not more than three years after the last actuarial valuation. Unless the Plan specifies otherwise, the date of each actuarial valuation must be at the Plan's fiscal year-end. If an amendment to the Plan or a change in Plan membership materially affects the cost of benefits provided by the Plan or creates an unfunded liability, an actuarial valuation must be prepared. Further, annual valuations are required when the Plan's solvency ratio is less than 120%. In the intervening period, contributions must be made in accordance with the last filed valuation.

The last actuarial valuation filed with OSFI was prepared as at January 1, 2022. The next actuarial valuation must be prepared and filed with OSFI no later than as at January 1, 2024 as the solvency ratio at this valuation date is less than 120%.

In order for an employer contribution to be eligible under a defined benefit provision, it must be recommended by an actuary in whose opinion the contribution is required to be made and the actuary's recommendation must be approved by the CRA. As such, in accordance with Section 147.2 of the *Income Tax Act (Canada)*, this entire valuation report must be filed with the CRA in support of eligibility of employer contributions.

We will file this report with the appropriate regulatory authorities on the Employer's behalf.

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3. Summary of Results

The principal results of the actuarial valuation are presented below. Further analysis of the results of the valuation is provided in Sections 4 and 5. The plan provisions, membership data, asset data, actuarial methods and assumptions are described in the appendices.

3.1 Funded Status – Going-Concern Basis

Based on the assumption that the Plan will continue indefinitely, the following is the funded status of the Plan on a going-concern basis:

	January 1, 2022 $	January 1, 2023 $
Actuarial value of assets	21,873,100	22,547,500
Actuarial liability	23,068,000	20,669,800
Actuarial excess (unfunded liability)	(1,194,900)	1,877,700
Funded ratio	94.8%	109.1%

The calculation of the actuarial value of assets is given in Appendix C.5. Details of the actuarial liability are given in Section 4. The reconciliation of the unfunded liability at the previous valuation to the actuarial excess at this valuation date is given in Section 5.

3.2 Funded Status – Solvency

A solvency valuation is used to measure the funded status of the Plan should it wind up on the valuation date and is prescribed by the Act. It follows certain adjustments as required under legislation.

	January 1, 2022 $	January 1, 2023 $
Solvency assets	24,021,300	21,301,600
Solvency liabilities	22,230,900	18,075,400
Solvency assets less solvency liabilities	1,790,400	3,226,200

In accordance with the Act and regulations, the solvency surplus (deficiency) is defined as the amount by which the aggregate of the *adjusted* solvency asset amount exceeds (is below) the solvency liabilities. For this purpose, the adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio and solvency deficiency are further described in Section 4.4.

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3.3 Current Service Cost and Contribution Requirements

The following table shows the annual cost of accruing benefits and expenses for employee service after the valuation date:

	January 1, 2022 $	January 1, 2023 $
Total cost of accruing benefits	313,300	203,200
Plus: Non-investment expenses	70,000	75,000
Less: Members' contributions	(39,600)	(30,400)
Company current service cost	343,700	247,800
As a % of member contributions	868%	815%
Minimum special payments	123,900	0
Minimum required Company contributions	467,600	247,800

A reconciliation of the current service cost is given in Section 5.3.

3.4 Minimum Required Contributions

The minimum required employer contribution is equal to the total of:

1. The employer current service cost for the year; plus
2. Special payments towards amortizing any going-concern unfunded liability over 15 years from the date on which the unfunded liability was established; plus
3. If there is a solvency deficiency, special payments equal to the amount by which the solvency deficiency divided by 5 exceeds the amount of the going concern special payments.

The employer current service cost is shown in Section 3.3.

As noted in Section 3.1, on a going concern basis the Plan has surplus and, as a result, no going concern special payments are required.

As noted in Section 4.4, the Plan has a solvency excess. As there is a solvency excess, no solvency special payments are required.

To satisfy the requirements of the Act and its Regulations, contributions to the fund must be made in accordance with the following rules:

- Required member contributions must be remitted to the pension fund within 30 days following the month in which the contributions were received from the member or deducted from his or her remuneration.
- Employer normal (i.e. current service) cost contributions and special payments must be remitted to the pension fund within 30 days after the end of the month for which the contributions are payable.

3.5 Maximum Allowable Employer Contribution

The maximum allowed employer contribution in the first year following the valuation date is equal to the total of:

1. The employer current service cost for the year; plus
2. The going-concern unfunded liability (if any); plus
3. The extra contribution required to fully fund the solvency deficiency (if any).

As of this valuation date, there is a funding excess and a solvency excess.

	2022 $	2023 $
Current service cost	343,700	247,800
Greater of unfunded liability and solvency deficiency	1,194,900	0
Maximum contribution	1,538,600	247,800

If the Employer wishes to make the maximum allowed employer contribution, it is advisable to contact the Plan actuary before making such contribution to ensure that contribution will be eligible and deductible and that any regulatory requirements are considered.

3.6 Excess Surplus

The ITA prescribes the maximum going concern surplus (before contingency reserves) that may be retained by the Plan while employer contributions continue. In general, this maximum is defined as 25% of the going concern actuarial liability allocated to the employer.

As at the valuation date, the Plan does not have an excess surplus, therefore employer contributions are not affected by the prescribed maximum surplus limit.

3.7 Subsequent Events

Subsequent events are events that transpire after the calculation date and before the date of this report. Subsequent events also include events that, as of the report date, are fully committed to occur in the future. The Employer has confirmed that there are no subsequent events that would materially affect the valuation results beyond those that have been noted in Section 2 above.

The impact of experience between the valuation date and the date of this valuation report differing from the actuarial assumptions will be determined at the next valuation.

3.8 Solvency Ratio

The Solvency Ratio is the ratio of the solvency assets to the solvency liabilities. If the Solvency Ratio is less than 1.0, certain conditions and restrictions, as prescribed by the Act, must be applied to the commutation of benefits from the Plan. Transfer values may be paid in full if the Company makes additional special payments to the Plan to cover the portion of the transfer value above the Solvency Ratio.

As at the valuation date, the Solvency Ratio is not less than 1.0, therefore additional special payment need not be remitted to the Plan at the time of transfer in order for transfer values to be paid in full.

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3.9 Next Required Valuation

Subsection 12(2) of the Act and section 2 of the Directives require that the effective date of the next valuation is within one year from the valuation date, unless the solvency ratio is 1.20 or greater. Since the solvency ratio of the Plan is below 1.20, the effective date of the next valuation must be no later than January 1, 2024.

3.10 Actuarial Opinion

Yukon Energy Corporation Employees' Pension Plan
Office of the Superintendent of Financial Institutions Registration Number: 56997
Canada Revenue Agency Registration Number: 1041011

We have prepared an actuarial valuation for the Plan as at January 1, 2023. In conducting the valuation, we have used the membership data, the custodial statements of the fund provided by Canada Life, and the actuarial methods and assumptions described in this report.

In our opinion, for the purposes of this report:

1. The data on which the valuation is based are sufficient and reliable;

2. The assumptions are appropriate; and

3. The methods employed in the valuation are appropriate.

We hereby certify that, in our opinion, as at January 1, 2023:

1. The Plan is fully funded on going-concern basis. The actuarial value of assets exceeds the actuarial liability by $1,877,700. The funded ratio is 109.1%.

2. The Plan's solvency assets exceeded the Plan's solvency liabilities by $3,226,200. The solvency ratio is 117.8%.

3. The average solvency ratio is 109.3% and the Plan has a solvency excess of $1,681,000.

4. The total annual employer contributions of $247,800, payable monthly, are required to fund the cost of the current year's benefits and non-investment expenses for the ensuing year. The estimated dollar amount of required employee contributions is $30,400. The employer current service cost is equivalent to 815% of required employee contributions.

5. As a funding excess exists on a going concern basis and there is no solvency deficiency, no special payments are required.

6. The Employer contributions recommended in this report are eligible contributions under Section 147.2(2) of the *Income Tax Act (Canada)*.

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7. We are not aware of any subsequent events, not already taken into consideration, that could materially affect the results of this valuation.

8. The next actuarial valuation should be conducted with a valuation date no later than January 1, 2024.

The content herein has been prepared exclusively from a financial viewpoint. This report does not constitute a legal opinion on the rights and duties of the plan administrator, the Employer or the members concerning the Plan.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada and in accordance with applicable legislation.

Actuarial valuation results are estimates only and are based on assumptions and methods developed in accordance with actuarial standards of practice. Emerging experience differing from the assumptions will result in experience gains and losses that will be revealed in future valuations.

Tom Kowalczyk
Fellow, Canadian Institute of Actuaries

Rory O'Connor
Fellow, Canadian Institute of Actuaries

George & Bell Consulting Inc.
June 29, 2023

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4. Assets and Liabilities

The following tables provide additional details of the assets and the liabilities of the Plan.

4.1 Plan Assets – Going-Concern Basis

The value of the assets used for this valuation is as follows:

	January 1, 2022 $	January 1, 2023 $
Market value of assets	24,156,300	21,486,600
Smoothing adjustment	(2,283,200)	1,060,900
Smoothed value of assets (1. + 2.)	21,873,100	22,547,500

An analysis of the change in the market value of the assets is given in Appendix C.4. The development of the smoothing adjustment is shown in Appendix C.5.

4.2 Details of Plan's Funded Status – Going-Concern Basis

The following table shows details of the Plan's funded status on a going-concern basis, including the actuarial liabilities for the different categories of members.

Going Concern	January 1, 2022 $	January 1, 2023 $
Actuarial value of assets	21,873,100	22,547,500
Actuarial liability		
Active members	9,759,100	5,333,900
Retired members	12,489,700	14,601,700
Deferred members	506,100	436,800
Flex contributions	313,100	297,400
Total	23,068,000	20,669,800
Going concern excess / (deficiency)	(1,194,900)	1,877,700
Funded ratio	94.8%	109.1%

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4.3 Details of Plan's Funded Status - Solvency Basis

The solvency valuation is prescribed by the Act to measure the funded status of the Plan should it wind up on the valuation date. A hypothetical wind-up valuation measures the same funded status, with minor differences, and is required under accepted actuarial practice. Since all benefits have been valued under this solvency valuation and assuming that the asset liquidation value would be equal to the market value of assets, the hypothetical wind-up funded status would be the same as the solvency funded status shown below.

The following table shows details of the Plan's funded status on a solvency basis.

Solvency	January 1, 2022 $	January 1, 2023 $
Plan assets		
Market value of assets	24,156,300	21,486,600
Estimated expenses on plan wind-up	(135,000)	(185,000)
Total hypothetical wind-up / solvency assets	24,021,300	21,301,600
Hypothetical wind-up / Solvency liabilities		
Active members	9,163,400	4,532,500
Retired members	12,151,600	12,752,200
Deferred members	602,800	493,300
Flex contributions	313,100	297,400
Total	22,230,900	18,075,400
Hypothetical wind-up surplus / (deficiency)	1,790,400	3,226,200
Solvency ratio	108.1%	117.8%
Average solvency ratio	103.0%	109.3%
Excess / (Solvency deficiency)	666,900	1,681,000

The hypothetical wind-up and solvency liabilities have been determined in accordance with a Plan wind-up scenario assuming no indexing would be provided to any Plan member (indexing is provided at the Plan sponsor's discretion).

The incremental cost of the solvency liabilities over the next year is estimated to be $394,300.

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4.4 Details of Solvency Excess (Deficiency)

The Average Solvency Ratio under the Regulations to the Act has been determined using the solvency ratios as at the valuation date and the two prior valuation dates.

The solvency ratios at the two prior valuation dates have been adjusted to increase the solvency assets by an amount not in excess of the present value of special payments made to the Plan in respect of the period between January 1, 2021 and January 1, 2023.

The average solvency ratio, adjusted solvency asset amount and solvency excess (deficiency) are determined as follows:

	January 1, 2021	January 1, 2022	January 1, 2023
	$	$	$
Solvency assets	21,698,800	24,021,300	21,301,600
Present value of:			
Special payments made in 2021	243,500	0	0
Special payments made in 2022	122,500	122,200	0
Adjusted solvency assets	22,064,800	24,143,500	21,301,600
Solvency liabilities	21,748,000	22,230,900	18,075,400
Adjusted solvency ratio	101.5%	108.6%	117.8%
Average solvency ratio			109.3%
Solvency excess (deficiency)			1,681,000

4.5 Solvency Liability Sensitivity

We have determined that if the solvency discount rate was reduced by 1% in both the calculation of lump sum values and annuity values, the solvency liabilities would increase by $2.1 million, or 11.7%.

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5. Reconciliation of Funded Status

This section provides additional analysis of the results, including the changes in the funded status during the inter-valuation period.

5.1 Reconciliation of Funded Status – Going Concern Basis

The following table reconciles the unfunded liability at the previous valuation with the unfunded liability at this valuation.

Reconciliation of financial position	$
Unfunded liability at January 1, 2022	(1,194,900)
Special payments and employer contributions in excess of annual cost	158,000
Expected interest (excluding effect of asset smoothing)	44,600
Expected funding excess at January 1, 2023	(992,300)
Plan experience	43,200
Gains and losses on assumption/method changes	
Discount rate	2,692,900
Retirement assumption	133,900
Unfunded liability at January 1, 2023	1,877,700

The analysis of the net Plan experience is given in Section 5.2.

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5.2 Analysis of Experience

The preparation of an actuarial valuation requires the actuary to make assumptions about future economic and plan experience. When the actual experience deviates from the expected experience, the Plan has an experience gain or loss.

The following table shows the main sources of the experience gains and losses noted in Section 5.1.

Experience gains and losses	$
Investment experience on market value of assets	(3,363,500)
Gain/(loss) due to asset smoothing method	3,344,100
Retirement experience	152,100
Mortality experience	3,300
Salary increases less (greater) than expected	41,000
Indexing less (greater) than assumed	(114,500)
Expenses less (greater) than assumed	(7,300)
Data corrections	(9,100)
Miscellaneous	(2,900)
Total	43,200

5.3 Reconciliation of Current Service Cost

The following table reconciles the current service cost at the previous valuation with that at the current valuation.

Reconciliation of Current Service Cost (as % of employee contributions)	
2022 current service cost	868%
Change in demographics	173%
Change in expense assumption	27%
Change in retirement assumption	-150%
Change in discount rate	-103%
2023 current service cost	815%

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5.4 Provision for Adverse Deviation and Future Expenses

The going concern liabilities and normal cost were determined using a discount rate net of investment expenses and a margin for adverse deviation. As a result, the liabilities and normal cost figures include amounts attributed to future investment expenses and a margin. In addition, an allowance for non-investment expenses is included in the normal cost. The present value of those amounts at the valuation date is summarized in the following table.

	Assumption	Present value in liability $	Present value in normal cost $
Margin for adverse deviation	Inherent in discount rate - 0.3%	710,000	8,000
Investment expenses – passive	Inherent in discount rate - 0.1%	241,000	3,000
Investment expenses – active	Inherent in discount rate - 0.3%	710,000	8,000
Non-investment expenses	$75,000 per year	n/a	75,000

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6. Stress Testing and Sensitivity

Accepted actuarial practice requires the disclosure of certain sensitivity results as well as the consideration of plausible adverse scenarios and their impact on the plan's funded status and current service cost.

6.1 Asset-Liability Mismatch: Interest/Discount Rate Sensitivity

As the assumed discount rate has a significant impact on the Plan's going concern liabilities, accepted actuarial practice requires that the impact on the going concern liabilities and current service cost of a 1.0% decrease in the assumed discount rate be disclosed.

The following table illustrates the effect of an immediate 1.0% decrease in future return expectations leading to a 1.0% decrease in the discount rate. The effect of this change on fixed income assets has also been included (as such a change would mean that fixed income yields would have decreased by 1.0% resulting in an immediate capital gain on the Plan's fixed income assets).

	Current Interest & Discount Rate	Interest Rate & Discount Rate 1% Lower	Percentage Change
Actuarial value of assets	22,547,500	22,726,000	0.8%
Actuarial liability	20,669,800	23,362,700	13.0%
Actuarial excess (unfunded liability)	1,877,700	(636,700)	
Funded ratio	109.1%	97.3%	
Solvency assets	21,301,600	22,194,300	4.2%
Solvency liabilities	18,075,400	20,193,400	11.7%
Solvency assets less solvency liabilities	3,226,200	2,000,900	
Solvency ratio	117.8%	109.9%	
Current service cost	247,800	279,900	13.0%
Minimum special payments	0	57,700	n/a
Minimum required Company contributions	247,800	337,600	36.2%

The Plan's liabilities have a duration of 13.0 years (based on a 1% decrease in the funding discount rate).

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6.2 Asset-Liability Mismatch: Deterioration of Asset Values

Investment policy may create an asset-liability mismatch should one asset class not produce the actual returns necessary to match the liabilities.

The following table shows the effect on the Plan's funded status of an immediate 20% decrease in the Plan's non-fixed income assets:

	Current Status	Immediate 20% Drop in Non-Fixed Income Assets	Percentage Change
Actuarial value of assets	22,547,500	20,319,600	-9.9%
Actuarial liability	20,669,800	20,669,800	0.0%
Actuarial excess (unfunded liability)	1,877,700	(350,200)	
Funded ratio	109.1%	98.3%	
Solvency assets	21,301,600	18,287,400	-14.2%
Solvency liabilities	18,075,400	18,075,400	0.0%
Solvency assets less solvency liabilities	3,226,200	212,000	
Solvency ratio	117.8%	101.2%	
Current service cost	247,800	247,800	0.0%
Minimum special payments	0	33,800	n/a
Minimum required Company contributions	247,800	281,600	13.6%

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6.3 Demographic Experience: Increased Longevity

This stress test offsets the mortality rates applicable to each member by one year, extending their life expectancy. The timing of all other decrements was unchanged.

The following table shows the effect this increased longevity has on the Plan's funded status and current service cost:

	Current Longevity	Increased Longevity	Percentage Change
Actuarial value of assets	22,547,500	22,547,500	0.0%
Actuarial liability	20,669,800	21,112,900	2.1%
Actuarial excess (unfunded liability)	1,877,700	1,434,600	
Funded ratio	109.1%	106.8%	
Solvency assets	21,301,600	21,301,600	0.0%
Solvency liabilities	18,075,400	18,388,300	1.7%
Solvency assets less solvency liabilities	3,226,200	2,913,300	
Solvency ratio	117.8%	115.8%	
Current service cost	247,800	251,500	1.5%
Minimum special payments	0	0	0.0%
Minimum required Company contributions	247,800	251,500	1.5%

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Appendix A - Plan Provisions

This summary contains the main provisions of the Plan as at the valuation date. For a complete description, reference should be made to the Plan text.

Background	The Plan became effective December 1, 1997 to replace the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies Plan 2 ("CU Plan") for employees of Yukon Energy. The provisions are identical to those of the CU Plan. Prior to January 1998, certain employees of Yukon Electrical Company Limited were given the choice to become employees of Yukon Energy effective January 1, 1998. The pension credits earned by these transferring employees under the CU Plan up to January 1, 1998 were transferred to the Plan together with assets to cover the pension credits transferred. Employees who transferred employment from the Yukon Electrical Company Limited to Yukon Energy joined the Plan effective January 1, 1998. The assets were transferred from the CU Plan to the Plan in December 1999. Effective January 1, 2002, the Plan was closed to employees hired on or after December 31, 2001. These employees will participate in the company Group RRSP. Active participants in the Plan have the option to transfer to the Group RRSP at any time.
Eligibility for Membership	Permanent full-time and part-time employees are eligible to join the Plan on the first of the month coinciding with or following the date of hire. Employees hired after December 31, 2001 are not eligible to join the Plan.
Continuous Service	The Period of an employee's uninterrupted employment with the Company, beginning with the date of employment. Includes Continuous Service under the CU Plan for employees who transferred from the CU Plan on January 1, 1998.
Pensionable Service	Expressed in years and completed months. Period of Continuous Service during which an employee made contributions to the Plan. Includes service transferred from the CU Plan as at January 1, 1998. Pensionable Service is pro-rated for part-time employees.
Pensionable Age	The earliest age at which a pension benefit is payable to the member under the terms of the plan without consent of the administrator and without reduction by reason of early retirement. Pensionable age is age 65.
Employee Contributions	Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. As part of the flex plan provision, employees can make additional contributions to purchase ancillary benefits on a cost-neutral basis to the Plan. Members choose the ancillary benefit on termination of service or on retirement.
Company Contributions	The Company pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary.

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Retirement Dates	**Normal Retirement Date** • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. **Early Retirement Date** • A member may retire without company consent starting at age 55. With Company consent, a member may retire starting at the earlier of age 55 and the date the member's age and service sum to 90. **Postponed Retirement Date** • A member who remains employed with the Company after age 65 continues to make pension contributions and accrue benefits under the Plan up to the earlier of his actual retirement and age 71.
Normal Retirement Pension	An annual pension for each year of Pensionable Service of: 1.4% of final average earnings up to the final average YMPE plus 2% of final average earnings in excess of the final average YMPE. Final average earnings are the annual average of the highest five years of pensionable earnings. Pensionable earnings are an employee's basic earnings, excluding northern allowance. Final average YMPE is the annual average of the YMPE's over the same period used to calculate the final average earnings. In addition, members may purchase ancillary benefits with their flex contribution balances upon retirement, termination or death.
Early Retirement Pension	If a member retires from active service with Company consent, the pension payable will be reduced as follows: • If age and service sum to 90 years or more, no reduction applies; • Reduced by the following percentages (but no more than an actuarial equivalent reduction), if age and service are less than 90: **Age** / **Reduction** 62-64 0% 61 3% 60 6% 59 12% 58 18% 57 24% 56 30% 55 36% If retirement is not from active service, or if Company consent for retirement was not obtained, an actuarial equivalent reduction from normal retirement date applies instead of the foregoing rules.
Normal Form of Pension	If the member has an eligible spouse at the earlier of retirement or termination, 60% of the retired member's pension continues to the surviving spouse. Otherwise, the pension is payable for the lifetime of the retired member, with a guarantee that pension payments will be at least equal to the member's contributions with interest. There is no reduction to the initial pension amount for a member with an eligible spouse to reflect the value of the spousal benefit.

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Death before Retirement	Commuted value of the member's pension, plus refund of contributions with interest, which exceed 50% of the commuted value of the member's pension.
Disability	Prior to January 1, 2008, a disabled member continued to accrue pensionable service and was not required to contribute to the plan. Effective January 1, 2008, a disabled member continues to accrue pensionable service provided he makes contributions during the period of disability. During a period which a disabled member accrues pensionable service, pensionable earnings is equal to his earnings rate immediately prior to becoming disabled and increased annually at 100% of the increase in the Consumer Price Index to a maximum of 3.0% per annum.
Termination Benefits	A deferred lifetime pension, based on the member's Pensionable Earnings, contributions and credited service up to the date of termination. If the member's contributions, plus interest, exceed 50% of the commuted value of the deferred pension, then the excess contributions are retained in the Plan, accumulated with interest, and used to provide additional benefits at retirement. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55. Alternatively, a terminated member who is entitled to a deferred pension (including the pension in respect of any excess contributions) may, prior to his attainment of age 55, elect to transfer the commuted value of his benefits to another locked-in vehicle, such as a locked-in RRSP or LIRA.
Credited Interest	Member contributions are credited with interest at a rate based on the average of Canadian chartered banks' 5-year Personal Fixed Term deposit rates.
Indexing	Pensions payable to members (including deferred vested members) are indexed only after the normal retirement date. Pensions payable to members who retire prior to the normal retirement date with Company consent are indexed after pension commencement. The indexing adjustment is determined annually at each January 1st by the Company, based on changes in the Consumer Price Index, subject to a maximum of 3% per year.
Maximum Pension Limit	The annual pension amount payable at retirement, excluding additional amounts due to any voluntary contributions, to a member is subject to the limitations under the Income Tax Act (Canada) and Regulations.

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Appendix B - Plan Membership

B.1 Source of Data

In performing the calculations, we obtained data from the Employer, including active members, pensioners and deferred pensioners. We have reviewed the data to ensure its completeness, accuracy and consistency with the data used in the previous valuation. Specific tests include:

- A member by member reconciliation of the membership group from the previous valuation to this valuation date;
- A reconciliation of birth, hire, and participation dates against the corresponding dates provided for the last valuation to ensure consistency of data;
- A reconciliation of credited service against the corresponding amount provided for the last valuation;
- A reconciliation of pensionable earnings against the corresponding amounts provided for the last valuation to identify any unusual increases or decreases;
- The accrued pension amounts for terminated members and pensioners were reconciled with corresponding data from the previous valuation;
- A reconciliation of any stated benefit payments in the inter-valuation period for retired, terminated or deceased members against the financial statements of the pension fund.

There was no information missing from the data, so no assumptions were required with respect to such data. The results of our tests were satisfactory and, in our opinion, the membership data are sufficient and reliable for the purposes of the valuation.

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B.2 Summary of Membership Data

The following tables summarize the key characteristics of the Plan membership as of the calculation date.

Number of Members	January 1, 2022	January 1, 2023
Active Members	8	6
Terminated Members with deferred pension	4	4
Retired Members (including beneficiaries)	24	26
Total	**36**	**36**

B.3 Changes in Plan Membership

The following table shows the changes in the Plan's membership since the previous valuation:

	Active	Retired, including beneficiaries	Deferred pensioners
Members at January 1, 2022	**8**	**24**	**4**
Terminations - Paid Out	0	0	0
Terminations - Deferred	0	0	0
Retirements	(2)	2	0
Deaths	0	(1)	0
Deaths - New Spousal Pension	0	1	0
Members at January 1, 2023	**6**	**26**	**4**

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B.4 Members - Details

	January 1, 2022	January 1, 2023
Active Members		
Number	8	6
Average age (years)	57.7	58.4
Average years of pensionable service	27.0	26.7
Average compensation for the following year	$132,500	*
Proportion female	12.5%	16.7%
Expected average remaining service lifetime (EARSL)	3 years	3 years
Deferred Members		
Number	4	4
Average age (years)	56.2	57.2
Average annual pension	$10,700	$10,900[1]
Proportion female	25.0%	25.0%
Retired Members / Beneficiaries		
Number	24	26
Number with bridge pensions	2[2]	1
Average age	69.8	69.9
Average annual lifetime pension	$30,500	$35,600
Average annual bridge pension	$1,300[3]	$800
Proportion female	20.8%	15.4%

** Not shown for confidentiality reasons.*

[1] Data correction to reflect additional pension due to 50% cost-sharing for one member.
[2] Corrected number of bridge pensions.
[3] The average annual bridge pension fell to $900 per month effective March 1, 2022.

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Appendix C - Plan Assets

C.1 Source of Plan Asset Information

The assets of the Plan are held in an insurance company policy with Canada Life and are managed by a number of different investment managers. This type of arrangement governs only the investment of the assets deposited into the fund and in no way guarantees the benefits provided under the Plan or the costs of providing such benefits. In performing the actuarial valuation and preparing the following summaries, we have relied on Canada Life's unaudited financial statements of the fund, and on other information provided by the Employer including the detailed contributions and expenses of the Plan during the inter-valuation period.

We have tested the asset value and have reconciled it with the value at the previous valuation. We have also examined the benefits paid from the fund and tested the amounts against the membership data, and the consistency of the investment earnings with the fund's asset mix and market rates of return in the inter-valuation period.

The results of our tests were satisfactory and, in our opinion, the asset data are sufficient and reliable for the purposes of the valuation.

C.2 Composition of Assets and Asset Mix

The Plan had invested assets (rounded) as of the current and previous valuations as follows:

	January 1, 2022		January 1, 2023	
	$	%	$	%
Long Bonds	8,824,200	36.5%	6,747,900	31.5%
Canadian Equities	3,973,300	16.4%	3,846,400	18.0%
U.S. Equities	3,287,300	13.6%	2,823,100	13.2%
International Equities	3,029,000	12.5%	2,712,300	12.7%
Real Estate	5,041,600	20.9%	5,273,800	24.6%
Cash	0	0.0%	0	0.0%
Invested Assets	**24,155,400**	**100.00%**	**21,403,500**	**100.00%**
Contributions receivable	0		74,600	
Benefits payable	0		0	
Expenses payable	900		8,500	
Market Value of Assets	**24,156,300**		**21,486,600**	

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C.3 Investment Policy Asset Mix

The Statement of Investment Policies and Procedures outlines the long-term target asset mix by market value as follows:

	Target
Long Bonds	40.0%
Canadian Equities	15.0%
U.S. Equities	12.5%
International Equities	12.5%
Real Estate	20.0%

C.4 Changes to the Plan Assets

The following table shows the changes to the assets, by market value, from the previous valuation date to this valuation date. The amounts were taken from the plan's fund statements, and include amounts receivable/payable, if any.

Beginning of Period	January 1, 2022
Opening Asset Value	24,156,300
PLUS	
Company Contributions	
Current service	365,000
Special Payments	127,600
Member Contributions	42,000
Flex Contributions	16,900
Investment Income	(2,231,200)
Subtotal	(1,679,700)
LESS	
Pension payments	789,800
Lump sum refunds	0
Investment fees	122,900
Administration Fees	77,300
Subtotal	990,000
Closing Asset Value	21,486,600
Gross rate of return	-9.3%
Rate of return net of investment expenses	-9.8%
End of Period	**December 31, 2022**

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C.5 Actuarial Value of Assets

As described in Appendix D, the actuarial value of assets is determined by modifying the adjusted market value of assets to recognize asset gains (losses) (i.e., the difference between actual investment return and expected investment return based on the valuation discount rate assumptions) over a 5-year period.

The smoothed value of the assets, including amounts receivable/payable, is derived as follows:

	Year	Multiplier	$
Adjusted Market Value of Assets			21,486,600
Less			
Unrecognized investment gains losses	2022	(3,410,100) x 80%	(2,728,100)
	2021	1,465,000 x 60%	879,000
	2020	1,043,400 x 40%	417,400
	2019	1,854,100 x 20%	370,800
			(1,060,900)
Preliminary smoothed value of assets			22,547,500
90% of market value of assets			19,337,900
110% of market value of assets			23,635,300
Adjusted smoothed value of assets			**22,547,500**

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Appendix D - Actuarial Methods

D.1 Components of the Minimum Required Contribution

The minimum required Employer contribution consists of three components:

- the current service cost, for service in the year following the valuation date;
- an amount to liquidate the unfunded liability, if any, on a going-concern basis; and
- an amount to liquidate the solvency deficiency, if any, on a solvency basis.

The value of the current service cost, the actuarial liability on both the going-concern and solvency basis, the value of the assets on the going-concern and the solvency basis, depend on the methods used in the valuation.

D.2 Actuarial Cost Method – Going-Concern Basis

As in the previous valuation, we have used the projected unit credit method to determine the actuarial liability and the current service cost of the Plan on the going-concern basis. Under this method, the actuarial liability is the present value of benefits earned for credited service up to the valuation date, based on pensionable earnings projected to retirement. The current service cost is the present value of benefits being earned for service in the year following the valuation date, based on projected earnings. The actuarial liability for the flex plan provision was taken to be the accumulated flex plan contributions with interest.

When calculating the actuarial present value of benefits at the valuation date, the present value of all retirement, withdrawal and pre-retirement death benefits are included. For each member, the retirement, withdrawal and pre-retirement death benefits for a particular period of service are first projected each year into the future taking into account early retirement entitlements and minimum pension entitlements. These projected benefits for each future year are then multiplied by the probability of the member leaving the Plan in that year and discounted with interest and survivorship to the valuation date. The actuarial present value of benefits for the particular period of service is then determined by summing the present values of these projected benefits.

As the Plan is now closed to new members, the average age of the active members will tend to increase over time. If all other things being equal, the current service cost will likely increase as a percentage of members' required contributions over time, although the dollar amount of current service cost will probably decline as the membership falls.

An actuarial excess is the excess of the actuarial value of assets over the actuarial liability; an unfunded liability is the excess of the actuarial liability over the actuarial value of assets, as the case may be.

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D.3 Actuarial Cost Method – Solvency Basis

We have used the accrued benefit method to determine the solvency liability. Under this method, we have estimated the amount of accrued benefits earned by each member as of the valuation date, and determined the actuarial present value of those benefits as of the valuation date as if the Plan had been wound up on that date.

We have calculated the liabilities as if the plan was terminated on the valuation date and the Employer exercised its discretion to determine the amount of future post-retirement indexing adjustment to be nil. The liability for the flex plan provision was taken to be the accumulated flex contributions with interest. The Plan's active members are provided with projections of their flex accounts and estimates of possible enhancements to minimize the impact of the "use-it-or-lose-it" rule. As a result, it would not be material to adjust the liability for the flex plan provision to account for the possibility of any gains that might be realized.

This valuation method is the same as the one used in the previous valuation. The actuarial assumptions used in the valuation are described in Appendix E.

D.4 Asset Valuation Methods

As in the previous valuation, the actuarial value of assets used in the going concern valuation has been determined by applying a smoothing methodology to the Plan's market value of assets at the valuation date.

Under this method, the actuarial value of the investment income for each year, net of investment expenses, is determined as the sum of the actuarially required net investment income on the market value of the assets plus an amortization adjustment. The actuarially required net investment income is determined as the amount of net investment income that results in a net rate of return on the market value of the assets equal to the assumed valuation discount rate for the year.

The amortization adjustment is determined by amortizing over a five-year period, the difference between the actual net investment income and the actuarially required net investment income.

The smoothed value is constrained to not fall outside the range of 90%-110% of the market value. The actuarial value of assets is also adjusted for contributions receivable and benefits and expenses payable as of the calculation date. The calculation is shown in Appendix C.

As in the previous valuation, the actuarial value of assets used in the solvency valuation was the market value of assets. The adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio, adjusted solvency asset amount and solvency excess/(deficiency) are determined in Section 4.4.

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D.5 Margin for Adverse Deviation

We have included a margin for adverse deviation of 0.3% in the going-concern discount rate, as described in Appendix E, to provide a level of conservatism in the funding of the Plan. No margin for adverse deviation is included in the solvency valuation.

D.6 Incremental Cost on a Solvency Basis

The incremental cost represents the present value, at the beginning of each period shown (time t), of the expected aggregate change in the solvency liabilities between time t and time t+1, adjusted upwards for expected benefit payments between time t and time t+1.

The calculation methodology can be described as follows:

1. the present value at time t of expected benefit payments between time t and time t+1, discounted to time t; plus
2. the projected solvency liabilities at time t+1, discounted to time t, allowing for, if applicable to the pension plan being valued:
    - expected decrements and related changes in membership status between time t and time t+1,
    - accrual of service to time t+1,
    - expected changes in benefits to time t+1, and
    - a projection of pensionable earnings to time t+1; less
3. the solvency liabilities at time t.

The actuarial assumptions used to calculate the incremental cost can be described as follows:

- The assumptions for expected benefit payments in item 1. above and decrement probabilities, service accruals, and projected changes in benefits and pensionable earnings in the item 2. above are consistent with the assumptions used in the Plan's going concern valuation.
- The assumptions used to calculate the projected solvency liabilities at time t+1 would generally be consistent with the assumptions for the solvency liabilities at time t, assuming that discount rates remain at the levels applicable at time t, that the select period is reset at time t for discount rate assumptions that are select and ultimate, and that the Standards of Practice for the calculation of commuted values and the guidance for estimated annuity purchase costs in effect at time t remain in effect at time t+1.
- No new entrants are considered in calculating the incremental cost.

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Appendix E - Actuarial Assumptions

In preparing the valuation, we used the following assumptions as estimates of future conditions that will affect the Plan.

The solvency valuation assumptions correspond to those prescribed by the applicable legislation.

Emerging experience, differing from the assumptions, will result in gains or losses, which will be revealed in future valuations.

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E.1 Assumptions Used in the Going-Concern Valuation

The going concern valuation is based on the assumption that the pension plan will continue to operate indefinitely into the future. We have made the following assumptions in the going concern valuation.

At each valuation, the past experience is compared to the assumptions made at the previous valuation to determine if, together with expectations of future trends, the assumptions should be changed. The experience gains and losses since the previous valuation are quantified and summarized in Section 5.2.

Going Concern Assumptions	January 1, 2022	January 1, 2023
Discount rate	4.4% per year	5.4% per year
Annual increase in general wages for Canada and Income Tax Act maximum pension	2.8% per year	No change
Salary increases	3.1% per year	No change
Inflation rate	2.0% per year	No change
Retirement	Retire when age plus service reaches 90 points, but not later than age 65. All active members are assumed to retire with Company consent	Retire when age plus service reaches 90 points, but not later than age 65. All active members are assumed to retire with Company consent Active members past 90 points or age 65 assumed to retire one year after the valuation date.
Mortality	CPM2014 Private table projected using Scale MI-2017; rates applied to post retirement only	No change
Withdrawal	No allowance	No change
Disability	No allowance	No change
Family composition	Current marital status; female spouse 4 years younger than male spouse if spousal age unknown	No change
Non-investment expenses	$70,000 per year	$75,000 per year
Interest on member contributions	2.2% per year	3.4% per year

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Economic assumptions

Discount rate – The primary economic assumption used in the going concern valuation is the discount rate, which is the rate of return that the assets are expected to earn over the long term, net of investment management expenses and a margin for adverse deviation. In this valuation, we have determined the discount rate as follows.

Derivation of Fund Rate of Return	Rate
Expected inflation	2.0%
Expected real return	3.5%
Value added for rebalancing/diversification	0.3%
Value added for active management	0.3%
Expected investment expenses	
Active investment management fees	(0.3%)
Passive investment management fees	(0.1%)
Non-investment fees	n/a
Margin for adverse deviation	(0.3%)
Discount rate	**5.4%**

In deriving the discount rate, we have assumed that the assets would be invested according to the Plan's investment policy.

Referring to the Bank of Canada's monetary policy, the inflation target is at 2.0% per year, the midpoint of the 1% to 3% inflation-control target range. Given this policy, historical inflation in Canada, and market expectations, an expected rate of inflation of 2.0% has been used.

The expected returns for the fund were estimated using our expected returns for applicable asset classes taking into account the target asset mix as outlined under the Plan's investment policy. Return assumptions for all asset classes are based on long-term expectations of at least 25 years.

The frequency of rebalancing the fund's weight in each asset class to its target in the investment policy, the weights themselves, and the time horizon, will all have an effect on the long-term return. The long-term return is also influenced by the diversification of the fund. The expected effect of rebalancing and diversification on the fund's return was estimated on the basis of a log-normal distribution.

Salary Increase Rate – The assumed future salary increase rate is 3.1% per year. This accounts for general wage increases in Canada plus increases due to merit and promotion.

Interest on Member Contributions – Interest is assumed to be credited on member contributions at 3.4% per year. The previous assumptions was 2.2% per year.

Non-investment Expenses – An explicit provision for non-investment expenses expected to be paid from the pension fund has been made by adding $75,000 to the current service cost, based on recent experience and future expectation. The previous assumption was $70,000.

Investment Expenses – It is assumed that future total investment expenses will be 0.4% of assets based on recent experience.

The goal of active management is to outperform the applicable benchmark index, after reduction for additional expenses. We expect for this portfolio that expenses for passive investment management would be approximately 0.1%. For the purpose of this valuation, it is assumed that additional returns due to active management will be 0.3%.

Benefit subject to consent – Assumed all members are granted consent for retirement and each year inflationary adjustments are made to pensions for eligible pensioners.

Demographic assumptions

Mortality (post retirement) – For the current valuation we used the 2014 Canadian Pensioner Mortality (CPM) Private Sector Table projected using improvement scale MI-2017. The incidence of pre-retirement mortality is assumed to be nil.

Retirement – In the previous valuation, we assumed that members would retire and commence receiving their pensions at their earliest unreduced retirement date assuming that the necessary consent is obtained (the earlier of age 65 or when age plus service reaches 90 points).

This assumption was modified to assume active members who are currently past 90 points or age 65 will retire one year after the valuation date in order to better estimate the normal actuarial cost. The assumption for active members who are not currently past 90 points or age 65 remains unchanged.

Termination of Membership – No allowance has been made for termination of employment prior to retirement due to plan experience and on the basis that the impact of including such an assumption would not have a material impact on the valuation results.

Disability – No allowance has been made for disability on the basis that the impact of including such an assumption would not have a material impact on the valuation results.

Family Composition – Current marital status is used and male spouses are assumed to be 4 years older than female spouses if spouse's age is unknown.

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E.2 Assumptions Used in Solvency Valuation

The solvency valuation is prescribed by the Act and is intended to determine the funded status of the Plan had it been terminated and wound up on the valuation date, but with certain differences and adjustments as required under legislation.

The benefits payable are determined as of the valuation date, without allowance for future salary escalation, and are assumed to be settled at that time. Active members at the valuation date who are eligible to retire are assumed to retire immediately with Employer consent; this assumption maximizes the value of benefits and reflects current Employer practice.

Solvency Assumptions	January 1, 2022	January 1, 2023
Discount rate		
Transfer value basis	2.1% per year for 10 years; 3.1% per year thereafter	4.3% per year for 10 years; 4.7% per year thereafter
Annuity purchase basis	2.9% per year	4.9% per year
Increase in the Income Tax Act maximum pension limit	2.8% per year	No change
Mortality table	CPM2014 Combined Table projected using scale B (sex distinct rates)	No change
Termination rates	Not applicable	No change
Retirement age	**Annuity Purchase Liability:** Best age if over age 55 or with 90 points, deferred to 65 otherwise **Lump Sum Transfer:** 50% at the best age if over age 55 or with 90 points and 50% at the earliest unreduced age, deferred to 65 otherwise	No change
Percent of liability assumed to be settled by purchase of annuity	50% of all active and deferred members, 100% of retired members	No change
Percent of liability assumed to be settled by lump sum transfer	50% of all active and deferred members, 0% of retired members	No change
Family composition	Current marital status; female spouse 4 years younger than male spouse if spousal age unknown	No change
Windup expenses	$135,000	$185,000

The discount rates and mortality tables for immediate and deferred annuity purchases are the rates implicit in the price of group annuities as at the valuation date, as determined by the Canadian Institute of Actuaries in their Guidance for Assumptions for Hypothetical Wind-up and Solvency Valuations Update – Effective December 31, 2022, and Applicable to Valuations with Effective Dates on or after December 31, 2022 and no later than December 30, 2023.

The duration of the liabilities expected to be settled by annuity purchase is 10 years.

The discount rates used to calculate the value of lump sum payments are the applicable rates as at the valuation date, determined in accordance with the Canadian Institute of Actuaries' Standards of Practice.

The weighted average on solvency liabilities of the annuity purchase rate and the commuted value rate as at the valuation date was 4.81%. The weighted average rates used in the prior two valuations are as follows and were used to calculate the special payments used to adjust prior solvency ratios:

Valuation Date	Valuation Weighted Solvency Rates
January 1, 2023	4.81% per year
January 1, 2022	2.72% per year
January 1, 2021	2.27% per year

Termination Scenario

The termination scenario used in the solvency and hypothetical wind-up valuation includes the following assumptions:

- Plan wind-up would not result from employer insolvency.
- All assets would be realized at their reported market value.
- Employment and membership in the Plan ceases on the valuation date.
- Active members not yet eligible to retire receive the termination benefit under the Plan.
- Active members already eligible to retire receive the retirement benefit under the Plan. Employer consent is granted for early retirement.
- Terminated vested members, retired members and beneficiaries receive the benefit to which they are entitled on the valuation date.
- Future post-retirement indexing adjustment is $nil.

This approach is the one used in the last valuation.

We did not make any projections of salary or YMPE increases in the solvency valuation.

We have projected the ITA maximum pension limit to the date of retirement in the calculation of the solvency liabilities. The ITA maximum pension limit was projected using a rate of 2.8% per year. The previous valuation used the same increase rate.

We have assumed the cost of winding up the Plan would be $185,000 and it includes expected expenses associated with operating the plan until all benefits are fully settled. It is assumed that all benefits would be fully settled two years after the wind-up date. In the previous valuation, the cost of winding up the Plan was assumed to be $135,000 and benefits would be fully settled one year after the wind-up date.

Finally, actual marital status was used and male spouses are assumed to be 4 years older than female spouses if spousal birth dates are unknown. The same assumption was used in the previous valuation.

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Appendix F - Data Certificate

EMPLOYER CERTIFICATE OF DATA

I hereby certify that the data submitted to George & Bell Consulting Inc. for the purpose of completing the January 1, 2023 Funding Valuation, the 2022 year-end calculations, and producing annual member statements as at December 31, 2022 for the Yukon Energy Corporation Employees' Pension Plan is, to the best of my knowledge, accurate and complete. The data provided includes, for each individual, 2022 pensionable earnings, 2022 plan contributions and 2022 credited service. Any anomalies queried by George & Bell Consulting Inc. with regard to inconsistencies in age, service, earnings, or contributions have been confirmed or corrected.

June 26, 2023
Date

Jason Epp
Chief Financial Officer
Yukon Energy Corporation

REFERENCE: **Application, PDF page 100**

ISSUE: Rate Schedule 35

QUOTE: Accordingly, this rate schedule was never implemented. As Minto mine ceased its mining operations, as discussed in Tab 2, this rate schedule is no longer required.

QUESTION:

a) Please confirm that YEC is asking for Rate Schedule 35 to be removed. If not confirmed, please explain why.

ANSWER:

(a)

Confirmed. Please see response to YUB-YEC-1-10(d).

REFERENCE: **Application, PDF page 107; Appendix A to Board Order 2018-10, par. 342; OIC 2021/16, Section 3, subsections 2-7**

ISSUE: Wholesale rates

QUOTE: Application, PDF page 107:

… and an Energy Reconciliation Adjustment provision which is intended to adjust charges to AEY that are attributable to AEY's wholesale purchases that vary from the wholesale forecast approved for YEC's last GRA. (Application, PDF page 107)

Appendix A to Board Order 2018-10, par. 342:

To be clear, ERA billing or refund amounts will be based on a consistent definition of costs. In this decision, the Board has clarified that actual costs for both the LWRF and the ERA are those costs related to actual thermal generation and not forecast thermal generation. Further, if significant industrial load enters or leaves the Yukon Integrated System or there are material changes in generation assets where either or both of these factors change the baseload generation mix, YEC can propose changes as to how the LWRF and the ERA operate at that time.

QUESTION:

a) Please explain whether, in YEC's view, OIC 2021/16 supersedes par. 342 of Appendix A to Board Order 2018-10.

b) If affirmative, please explain and cite which sections/subsections of OIC 2021/16 support YEC's view.

ANSWER:

(a) and (b)

OIC 2021/16 does not supersede the direction in the first sentence of par. 342 of Appendix A of Board Order 2018-10 that ERA billing or refund amounts must be based on a

consistent definition of costs, because the direction in that paragraph continues to apply after OIC 2021/16.

Going forward, however, the referenced costs must be determined for the purpose of applying that direction in the first sentence of par. 342 based on the LWRF provisions in OIC 2021/16 (adding section 9 to the Rate Policy Directive (1995)). Those provisions provide a mandatory formula for determining forecast fuel costs that is based on forecast thermal generation, which is determined having regard to LTA annual renewable source availability. This takes precedence over the statement in the second sentence of par. 342, where the Board stated previously that “actual costs for both the LWRF and the ERA are those costs related to actual thermal generation and not forecast thermal generation.”

Board Orders 2023-07 and 2023-11 approved ERA payments to YEC for 2021 and 2022 respectively are consistent with the above understandings regarding consistency with LWRF determinations as required by OIC 2021/16.

REFERENCE: **Application, PDF pages 141-148, Tables 5.2-5.5**

ISSUE: **General Plant**

PREAMBLE: The Board seeks further information on items included in General Plant.

QUESTION:

a) Please provide a single table including all General Plant projects broken down by year, with additional columns showing the capital costs and any applicable AFUDC, showing AFUDC separately from the capital costs. If a row is described as “Other Projects”, then provide a breakdown of those other projects with separate capital and AFUDC costs. Add two further columns to the table, one cross-referencing any applicable business cases for those items; if there is no business case, insert “N/A” into that column. In the second additional column, indicate whether the item is new or a replacement.

ANSWER:

(a)

Please see table attached as YUB-YEC-1-58 Attachment 1.

Project	2021	AFUDC	Total	2022	AFUDC	Total	2023	AFUDC	Total	2024 (Total)	Business Case	New / Replacement
Major Crane Assessment/Refurbishment	292,601.57	233.35	292,834.92							700,000.00	5.1B-17	Replacement
Server Replacements	16,156.68	2,596.80	18,753.48								5.1B-17	Replacement
Vehicle Purchases				459,604.14	4,207.14	463,811.28	620,550.86	3,233.14	623,784.00	567,010.00	5.1B-18	Replacement
New Mobile Office Unit - IT				184,623.68	610.99	185,234.67	616,986.74	8,013.26	625,000.00		5.1B-18	Replacement
Aishihik Bridge Redecking				108,898.37	355.20	109,253.57					5.1B-17	Replacement
Compact Digger Truck							199,305.54	694.46	200,000.00		5.1B-19	New
Skid Steer							188,809.15	217.85	189,027.00		5.1B-19	New
Mayo-McQuesten Radio to Fiber Migration							42,265.71	2,734.29	45,000.00		5.1B-20	New
Waste Management Equipment							109,951.11	48.89	110,000.00		5.1B-20	New
HQ Datacenter Server Replacement							20,000.00	-	20,000.00	280,000.00	5.1B-21	Replacement
SCADA Operation Network Segregation							119,898.64	101.36	120,000.00	125,000.00	5.1B-21	Replacement
Other Projects												
Computer Replacements	87,286.20	1,502.61	88,788.81	59,077.10	703.13	59,780.23	74,610.91	389.09	75,000.00	75,000.00	N/A	Replacement
Battery Bank Replacements for Substations and Plants	72,680.55	755.02	73,435.57	95,444.09	1,040.19	96,484.28	94,715.63	284.37	95,000.00	50,000.00	N/A	Replacement
Mayo Earthworks	51,001.33	568.21	51,569.54								N/A	Replacement
Operations Tools & Equipment - Blanket	32,814.13	-	32,814.13	37,650.13	-	37,650.13	40,000.00	-	40,000.00	40,000.00	N/A	Both
Office Furniture and Fixtures - Blanket	24,896.80	-	24,896.80	23,645.04	-	23,645.04	40,000.00	-	40,000.00	25,000.00	N/A	Both
Property Fencing Program	24,239.00	78.68	24,317.68	23,630.00	76.70	23,706.70	39,455.30	544.70	40,000.00	25,000.00	N/A	Replacement
Roofing - Block 8 Mayo Airport Subdivision Staff	21,480.79	70.60	21,551.39								N/A	Replacement
Roofing - 1136 5th Ave Dawson Transient Staff	19,980.79	65.73	20,046.52								N/A	Replacement
Printers/Scanners/Copiers/Fax Machine	17,538.50	-	17,538.50	23,800.00	77.25	23,877.25	23,000.00	-	23,000.00	15,000.00	N/A	Replacement
Safety Improvements - Blanket	13,676.63	-	13,676.63	4,876.25	-	4,876.25	25,000.00	-	25,000.00	25,000.00	N/A	Both
Hatchery Upgrades - Blanket	12,296.90	-	12,296.90				25,000.00	-	25,000.00	25,000.00	N/A	Both
Water Improvement Upgrades	6,625.79	50.60	6,676.39								N/A	Replacement
Mobile Radio Replacement	4,731.00	5.12	4,736.12	4,250.01	7.22	4,257.23					N/A	Replacement
Security Risk Management - Blanket	4,000.00	-	4,000.00								N/A	Replacement
SCADA Upgrade Program	3,810.24	51.80	3,862.04	2,962.14	53.46	3,015.60	9,931.66	68.34	10,000.00	10,000.00	N/A	Both
Facilities Signage - Blanket	2,205.45	-	2,205.45	2,259.13	-	2,259.13	15,000.00	-	15,000.00	15,000.00	N/A	Both
Data Storage Replacements and Additions	-	723.40	723.40								N/A	Both
Network Improvements	-	707.40	707.40	41,658.12	266.69	41,924.81	49,657.68	342.32	50,000.00	50,000.00	N/A	Both
Compact Digger Truck	428.22	8.78	437.00	-	11.16	11.16					5.1B-19	New
Vehicle Purchases	224.00	2.64	226.64								5.1B-18	Replacement
Mayo-McQuesten Radio to Fiber Migration				88,812.53	814.12	89,626.65					5.1B-20	New
Pole Trailer				60,574.95	196.63	60,771.58					N/A	Replacement
Records Storage Facility				56,231.74	865.74	57,097.48					N/A	New
Rose Hill Repeater Building Upgrade				43,977.84	246.50	44,224.34					N/A	Replacement
WH0 Battery UPS				39,629.59	147.00	39,776.59					N/A	Replacement
Confined Space Entry Mitigation				37,579.61	121.98	37,701.59					N/A	New
WH Vibrating Wire Piezometer Connection				28,631.95	173.64	28,805.59					N/A	New
IT Equipment & Software - Blanket				14,755.40	-	14,755.40	15,000.00	-	15,000.00	15,000.00	N/A	Both
Marsh Lake Access Road Refurbishment				13,097.24	75.54	13,172.78					N/A	Replacement
Dawson Office Air Conditioning Second Floor				9,752.23	-	9,752.23					N/A	New
Eng Services Tools & Equipment - Blanket				9,216.13	-	9,216.13	15,000.00	-	15,000.00	15,000.00	N/A	Both
AH Piezometer Upgrades				2,843.58	12.79	2,856.37	1,411.67	88.33	1,500.00		N/A	New
Fish Ladder TWG Recommendations							95,000.00	-	95,000.00		N/A	Both
Specialized Vehicle Purchases							34,827.30	172.70	35,000.00	35,000.00	N/A	Replacement
Fish Ladder Visual Aids							24,985.23	14.77	25,000.00		N/A	New
Server Replacements							20,000.00	-	20,000.00	20,000.00	5.1B-17	Replacement
EV Charging Stations							18,750.00	-	18,750.00		N/A	New
Faro Satellite Backup Comms Link										80,000.00	N/A	New
Stewart Crossing Satellite Backup Comms Link										80,000.00	N/A	New
Minto Landing Fiber Installation										60,000.00	N/A	New
Public Safety School Visit Displays										50,000.00	N/A	New
Lewes Control Structure Fiber Installation										40,000.00	N/A	New
WH4 Wing Wall Concrete Replacement										30,000.00	N/A	Replacement
S170 Substation Building Roof Replacement										20,000.00	N/A	Replacement
Subtotal - Other	399,916.32	4,590.59	404,506.91	724,354.80	4,889.74	729,244.54	661,345.38	1,904.62	663,250.00	800,000.00		
Total	708,674.57	7,420.74	716,095.31	1,477,480.99	10,063.07	1,487,544.06	2,579,113.13	16,947.87	2,596,061.00	2,472,010.00		

REFERENCE: **Application, PDF pages 141-148, Tables 5.2-5.5**

ISSUE: Intangible assets

PREAMBLE: The Board seeks further information on items included in intangible assets.

QUESTION:

a) Please provide a single table including all intangible asset projects broken down by year, with additional columns showing the capital costs and any applicable AFUDC, showing AFUDC separately from the capital costs.

ANSWER:

(a)

Please see table attached. Note – AFUDC for 2023 represents actual to date. AFUDC is not included for 2024 forecast numbers due to estimating challenges as actual will depend on project duration and timing of spending.

Project	2021			2022			2023			2024
	Capital Cost	AFUDC	Total	Capital Cost	AFUDC	Total	Capital Cost	AFUDC	Total	Capital Cost/ Total
PAMMS Asset Management Framework	217,229.74	85,563.21	302,792.95	733,706.81	100,932.44	834,639.25	909,816.89	101,183.11	1,011,000.00	
EAM Purchase and Implementation	726,228.61	42,072.32	768,300.93							
EAM Enhancements Review				146,275.35	1,062.06	147,337.41				
CIS Replacement				3,295.49	25.44	3,320.93		987.40	115,000.00	
Network Software Traffic Shaping							250,000.00	-	250,000.00	
P&C Central Event Data Collection System										150,000.00
SharePoint Upgrades										100,000.00
Other Projects										
IT Equipment & Software - Blanket	4,588.45	-	4,588.45	2,636.68	-	2,636.68	10,000.00	-	10,000.00	10,000.00
Prophix Labour Reporting	-	420.86	420.86							
My Account	51,806.20	812.42	52,618.62							
ASPEN System Protection Model and Relay Database				49,930.24	267.28	50,197.52				
Operations Power Simulator				35,655.05	0.90	35,655.95				
Biennial ERP System Upgrades				42,306.46	195.38	42,501.84				
CIS Replacement ATIPP Impact				1,498.72	14.19	1,512.91				
Customer Outage Notification System				1,267.06	6.85	1,273.91	59,901.91	98.09	60,000.00	
SCADA Network Engineer Access										80,000.00
H&S Management Software										20,000.00
IT Ticketing System										20,000.00
Subtotal - Other	56,394.65	1,233.28	57,627.93	133,294.21	484.60	133,778.81	69,901.91	98.09	70,000.00	130,000.00

REFERENCE: **Application, PDF pages 63, 142, 144, 146 and 148, Tables 5.2 to 5.5**

ISSUE: Non-fuel O&M - Capital / Maintenance forecast allocation of labour expense

QUOTE: In addition to the factors affecting labour listed above, the capital/maintenance forecast allocation also impacts the forecast labour expenses. YEC estimates the percentage of time each position will spend on capital and non-capital works. This assessment is based on past experience as well as expectations for the coming year. This allocation directly impacts the revenue requirement in any given year as maintenance charges are directly expensed while capital labour is reflected in expenses such as depreciation after the project is completed and placed into service. The 2021 approved revenue requirement forecasts included an allocation set at 17.2% capital and 82.8% maintenance. For the 2023 test year the forecast allocation is 17.9% capital and 82.1% maintenance and for the 2024 test year the forecast allocation is 18.4% capital and 78.6% maintenance. The ratio is based on YEC'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.

PREAMBLE: On Tables 5-2 to 5-5, YEC provided its capital expenditure amounts for 2021-2024 as follows: $22.2 million (2021 actual); $27.5 million (2022 actual); $58.9 million (2023 forecast) and $30.8 million (2024 forecast).

QUESTION:

a) Given the significant capital forecast for the years 2023 and 2024, please explain why YEC's forecast labour allocation between capital and maintenance costs has changed only minimally.

b) What were the actual 2021 and 2022 capital/maintenance allocations of labour expense on a dollar basis and percentage basis?

ANSWER:

(a)

The majority of capital project costs are materials and contractor costs. For example, the thermal replacement and Battery projects make up a large portion of the capital program, but much of the costs are for the equipment (diesel engines and the batteries).

(b)

Please see the table below.

	2021 Actual		2022 Actual	
	($000's)	%	($000's)	%
Capital	$2,640	16.7%	$2,077	13.2%
Non-Capital	$13,167	83.3%	$13,675	86.8%

REFERENCE: **Application PDF pages 141-148, Table 5.2 to Table 5.5 (years 2021-2024, respectively); PDF pages 231-235, Section 5.2A-1: Aishihik Generating Station Five-Year Licence Renewal (Additions to Rate Base of $3.903 million in 2022 and $0.575 million in 2023)**

ISSUE: Work-in-progress continuity schedules - Aishihik license renewal

QUOTE: Process leading to 5-Year Renewal

Following a multi-party planning process, Yukon Energy submitted a YESAA Project Proposal for a 25-year licence renewal to the Haines Junction Designated Office (DO) of the Yukon Environmental and Socio-Economic Assessment Board (YESAB) on July 10, 2020. An application for a 25-year licence renewal was subsequently filed with the Yukon Water Board (YWB) on May 31, 2021.

The Designated Office Evaluation Report was issued on June 18, 2021. In that report, the Haines Junction Designated Office declined to assess the proposed licence renewal for the 25-year period requested by Yukon Energy, and instead decided to confine the temporal scope of the assessment to 5 years. A Decision Document for a 5-year renewal term was subsequently issued on October 21, 2021 by the Government of Yukon and Fisheries and Oceans Canada. As a result of these regulatory decisions, the YWB's jurisdiction to renew the AGS water licence was confined to the 5-year period assessed by the Designated Office, from January 1, 2023 to December 31, 2027 (pursuant to section 86 of YESAA), and Yukon Energy had no feasible option other than to revise its Water Use Licence Renewal application to be limited to that 5-year period.

PREAMBLE: The Board requires further clarification of the costs related to the Aishihik license renewal.

QUESTION:

a) Referring to PDF page 144, Table 5.3 (2022) note, please confirm that the Notes quoted as: "** Reflects $1.3 million spending in 2022 and $5.7 million transfer to long-term relicensing project [25-year license]" is in reference to the line identified

as "*** Aishihik 5-Year License Renewal" on Table 5.3 (2022) and the line identified as "Aishihik 25-Year License Renewal" on PDF page 151, Table 5-7.

b) Referring to PDF page 144, Table 5.3 (2022), please explain the negative capital expenditure in the amount $4,421.50 thousand shown at the line identified as "*** Aishihik 5-Year License Renewal".

c) If the response to part (b) is that the negative capital expenditure of $4,421.50 thousand is related to the Aishihik 25-Year License Renewal, please indicate where the transfer of that amount between projects is indicated on Table 5.3 (2022) as a positive capital expenditure of $4,421.50 thousand.

d) Referring to the above quote, on what basis should YEC be including the costs for requesting an Aishihik 25-year License Renewal as a potential future capital asset as opposed to expensing those costs in the year 2022? Provide support for the response, including a reference to any business case prepared that contemplated an Aishihik 25-year License Renewal.

e) Please confirm that the costs respecting YEC's most recent Aishihik 3-year license renewal (January 1, 2020 to December 31, 2022) were in the amount of $1.004 million on an actual basis. If not confirmed, please explain.

f) Please confirm that costs respecting YEC's most recent Aishihik 5-year license renewal (January 1, 2023 to December 31, 2027) were in the amount of $4.478 million ($3.903 million in 2022 actuals and $0.575 million in 2023 forecast costs). If not confirmed, please explain.

g) Please confirm that costs respecting YEC's proposed Aishihik 25-year license renewal are in the amount of $7.2 million ($5.7 million in actual costs to 2022 and $1.1 million in forecast 2023 costs and $0.400 million in forecast 2024 costs). If not confirmed, please explain.

h) Please provide detail in support of YEC forecasts of additional costs in 2023 ($1.1 million) and 2024 ($0.4 million) for the Aishihik 25-year License Renewal, including an explanation in support of the viability of this project.

i) Please confirm that YEC's 2023-24 forecast reflects the inclusion of AFUDC on its proposed Aishihik 25-year license renewal.

j) Referring to the responses to parts (f), (g), and (h), please provide an explanation for what appear to be exponential increases in the cost of renewing the license on a three-year, five-year, and 25-year basis.

ANSWER:

(a)

Confirmed.

(b) and (c)

The $4.4 million negative amount referenced reflects the net amounts after allocation from the Aishihik 5-year Licence Renewal to the Aishihik 25-year License Renewal which is included in Table 5.7. As the note to Table 5.3 explains, this $4.4 million reflects $1.3 million spending in 2022 offset by $5.7 million transfer to long-term relicensing project [25-year license]. The $5.7 million transfer then shows up in Table 5.7 as the opening balance for 2023 for Aishihik 25-year License Renewal.

(d)

Attachment 5.2A, Section 5.2A notes that a material portion of costs incurred to date related to impact assessment, monitoring, stakeholder engagement and consultation and other costs incurred over 2015 to 2018 are considered foundational costs incurred to support the 25-year licence renewal. While a portion of costs were allocated to the 3-year and 5-year renewals, it was not considered appropriate to fully allocate these costs to the short-term renewal processes given they were primarily incurred to support a long-term renewal (see footnote 2 at page 5.2A-3). Further, given that much of this work will form the basis for documentation required to support the required 25-year long-term renewal process, it was not considered appropriate to expense these deferred costs in 2022.

The AGS 25-Year water use licence renewal process will not be completed until after the test years – and the full justification for these costs will be provided at the next GRA after the long-term licence renewal process has been completed.

(e)

Not confirmed. The $1.004 million was the forecast amount included in the 2021 GRA when the GRA was filed.

As outlined in Board Order 2022-03, final costs were $0.917 million (see paragraph 294 of that Order which reference Information Request YUB-YEC-2-17, page 16 of 29). YUB-YEC-2-17 from the 2021 GRA notes that actual costs for 2020 were lower than forecast due to project management and assessment and review process activities being lower than forecast.

(f)

The forecast cost included in the 2023/2024 GRA Application was $4.479 million, including $3.903 million closed in 2022 and a forecast of $0.575 million in 2023.

On further review, however, YEC has concluded that the forecast cost included in the GRA did not fully reflect the total costs for the 5-year license, including community and individual compensation, as well as securing the *Fisheries Act* Authorization, which has been extended into late 2024 due to the time necessary for the FAA renewal process to be completed. The corrected total forecast cost at completion for the 5-year license is $5.521 million, including $3.903 million closed in 2022, a forecast of $0.868 million in 2023 and a forecast of $0.750 million in 2024. YEC will reflect this change in the compliance filing.

(g)

Not confirmed. The costs in Table 5.7 are forecast costs to 2024 and do not include forecast costs beyond 2024. The total forecast cost, based on information available today, is about $8.3 million.

(h)

Forecast costs in 2023 and 2024 (Table 5.7) relate to costs that remain in WIP for these test years. These forecast costs are to collaboratively work with CAFN and YG to complete a Monitoring and Adaptive Management Plan (MAMP) and to commence work as required to prepare a YESAA Project Proposal for a 25-Year Licence Renewal. To be clear, Yukon Energy is not seeking to have these costs included in rate base at this time. As noted, Yukon Energy will provide a full justification for project costs when it seeks to have such costs included in rate base at a GRA when the 25-Year relicensing project is completed.

Section 5.2A-1 of Appendix 5.2A outlines the requirement for renewal of the AGS water use licence on terms substantially similar to the 2002 water use licence. At the end of the current five-year renewal [which expires on December 31, 2027], YEC requires a further licence renewal in order to continue operation of this critical YIS facility. YEC continues to plan, consistent with current submissions and directions, for the next renewal of its water use licence to achieve the desired maximum allowed term of 25 years. Failure to secure this longer term would result in further costs being required for additional short-term renewals.

The viability of obtaining a 25-year renewal subsequent to the current five-year renewal is supported at this time by significant engagement efforts completed over 2020 and 2021 which led to development and completion of agreements with key stakeholders (Yukon Government [YG] and Champagne and Aishihik First Nations [CAFN]). In July 2022, CAFN, YG and YEC entered into a suite of bilateral and trilateral agreements to structure and guide their ongoing relationship.[1] The agreements between the three parties include provisions aimed at guiding the parties' ongoing collaborative work related to the long-term renewal of the water use licence for the AGS. The structure in place provides for processes to address relevant matters of interest between the parties; and to address disputes should they arise. These agreements were not in place for the earlier short-term renewal processes, and will provide a framework for the parties to work collaborative to complete a long-term licence renewal prior to the end of 2027 (when the current 5-year WUL expires).

Please see also response to part (j).

[1] See Waterline Exhibits 1.14 Non-confidential overview of agreements and 10.11 Collaboration Agreement-Section 12.

(i)

Forecast costs reflect AFUDC. However, Yukon Energy is not seeking approval of Aishihik Generating Station 25-Year licence renewal costs at this time, and these costs are not included in rate base in the test years.

(j)

The AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA and the 2021 GRA. Specific updates regarding work completed and project costs for the long-term licence were reviewed in detail in YUB-YEC-1-90 filed during the 2021 GRA (see Attachment 1 to this response). This response noted two key factors accounting for the added time and cost requirements for the relicensing project:

- The long-standing concerns of Champagne and Aishihik First Nations (CAFN) with regard to this facility's origins and ongoing impacts; and

- The Yukon Government's decision by early 2019 to engage in negotiation of an agreement with CAFN to address issues of concern including reconciliation.

The use of a collaborative process with CAFN from 2016 to 2018, prior to the 2019 filing and over 2020 and 2021 resulted in very material increases in effort and related costs and a significantly longer process than originally envisioned. The only way to reduce these costs would have been to reduce the level of collaboration with CAFN regarding the relicensing process. However, in the context of the Water Use Licence and a Yukon government led agreement process with CAFN related to this project and other outstanding issues, this was not feasible – and any such option would not have had any assurance that the end result would have secured the required licence.

The extensive process has resulted in the completion of bilateral and tri-lateral agreements between YEC, YG and CAFN that provide greater clarity with regard to how the parties will work collaboratively going forward and which will support the completion of a long-term renewal prior to the end of 2027. The experience gained with the Aishihik licence renewal has also guided development of engagement processes with YG and the appropriate First Nations Governments for renewals of water use licences needed set to expire in 2025 for YEC's Whitehorse and Mayo hydro facilities.

Additional costs have also been incurred due to the added short-term renewal process in 2020/21. See Section 5.2A-1 of Appendix 5.2A which outlines the process leading to the 5-Year licence renewal. In summary, the following is noted:

- Yukon Energy submitted a Project Proposal in July 2020 to support a 25-year renewal of the AGS Water Use Licence.

- The Designated Office declined to assess the proposed licence renewal for the 25-year period requested by Yukon Energy and decided to confine the temporal scope of the assessment to 5 years.

- A Decision Document for a 5-year renewal term was subsequently issued by Yukon Government and the Department of Fisheries and Oceans DFO).

- As a result of these regulatory decisions, the Yukon Water Board jurisdiction to renew the AGS water use licence was confined to the 5-year period assessed by the Designated Office.

Based on the above, Yukon Energy had no feasible option other than to revise its water use licence renewal application to be limited to a 5-year period and plan to apply for a 25-year water use licence renewal at a later date. This added process, driven by regulatory requirements, has required additional costs to be incurred.

REFERENCE: **Application, Appendix 5.3, page 5.3-2**

ISSUE: **Aishihik Generating Station (AGS) Long-Term Water Use Licence Renewal Project**

QUOTE: "The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was $3.569 million spread over five years (2015-2019) … The deferred costs forecast in the Application include spending in WIP increasing from $4.957 million at the end of 2018 to $7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022."

QUESTION:

a) Please break down the $7.918 million cost for this project into the various components of the project and provide a description of why each component is necessary for the project to proceed.

b) Please explain why the total cost of this project has increased from $3.569 million in the 2017-18 GRA to $7.918 million in the current application.

c) Please provide a description of each new cost item and each cost item that has increased since the previous GRA, along with a description of why the new cost item or the increased cost is necessary.

d) Please include an explanation of why YEC's initial cost estimate was less than half of the current estimate and the measures YEC has implemented or plans to implement to improve its ability to forecast the costs of projects like this.

e) Please describe the actions YEC has taken throughout the duration of this project and the actions YEC plans to implement moving forward to control and minimize the costs of this project.

ANSWER:

(a)

The $7.918 million cost noted in Appendix 5.3 of the Application provided forecast project costs to the end of 2021, including 2020 forecasts. These costs now need to be updated to reflect revised forecast costs for 2020, 2021 and 2022.

As set out in Table 1 below – costs forecast to the end of 2021 are now expected to be $0.871 million higher than forecast in the Application. See Table 2 (response to (b) and (c) below) for updated forecast costs to the end of 2022.

Table 1: Project Costs - 2018 WIP to 2021 WIP

	2018 WIP Actual Cost	2019 Actual Cost	2020 Actual Cost	Forecast 2021	Total
Project Management	$276,268	$1,247	$152,946	$200,000	$630,461
CAFN Compensation & Stakeholder Engagement	$705,319	$2,373	$1,012,811	$350,000	$2,070,503
Impact Assessment Studies	$3,748,543	$94,741	$406,438	$ -	$4,249,722
Early Monitoring	$ -	$226,900	$258,049	$65,000	$549,949
Permitting processes	$40,218	$182,847	$303,625	$325,000	$851,690
Aishihik Advisory Committee	$186,851	$4,648	$4,935	$ -	$196,434
Future AFUDC*	$ -	$ -	$ -	$240,000	$240,000
Project Total:	**$4,957,199**	**$512,755**	**$2,138,804**	**$1,180,000**	**$8,788,758**

*Note: Previous AFUDC accruals for actuals 2018WIP, 2019 and 2020 are embedded within each category total

Set out below are descriptions of the various cost components (and why they are necessary for the project is as follows):

- Project management costs are primarily YEC internal costs related to work on planning and executing the project. These costs are required to move the project forward and coordinate the various working groups and deliverables.

- CAFN Compensation and stakeholder engagement costs are related to the following:

    1. Engagement with the CAFN, including funding the Champagne and Aishihik Community Advisory Committee (CACAC);
    2. Compensation to the CAFN to be approved by the Yukon Water Board;
    3. Negotiation costs to reach a reconciliation agreement with the CAFN;
    4. Capacity funding to CAFN to support participation in the project technical review and development of the Monitoring and Adaptive Management Plan and
    5. Public engagement activities.

  YEC deemed it prudent to engage the CAFN at the beginning of the current water use license renewal process, given that the facility is located within the CAFN's traditional territory. The objective of engagement was to increase participation by the CAFN in the water use relicensing regulatory process, increasing collaboration between YEC and CAFN and reducing the risk of conflict and/or adversarial legal action during the formal regulatory proceedings.

- Impact assessment studies costs are related to the planning and execution of the environmental and social impact assessment studies in preparation for the YESAB and Yukon Water Board applications. These costs are required to be able to prepare the Project Proposal for the YESAB Designated Office and develop a Monitoring & Adaptive Management Plan for the Yukon Water Board application.

- Early monitoring costs are related to early monitoring carried out to address issues relevant to CAFN, YESAB and regulators (including requirements from 3-year license to support 25-year renewal).

- Permitting process costs are required to complete the regulatory activities which are mandatory to achieve the primary objective of the project (obtaining a 25-year water use license for the facility). They include: 1) the project proposal to the Yukon Environmental and Socio-economic Assessment Board (YESAB); 2) regulatory application to the Department of Fisheries and Oceans (DFO); and 3) regulatory application to the Yukon Water Board (YWB).

- Aishihik Advisory Committee (AAC) costs related to funding the activities of the AAC from 2015 to 2018. The AAC's role was to provide ongoing advice and feedback as Yukon Energy and CAFN developed the necessary regulatory applications. In addition, the AAC worked to reconcile potential opposing interests and values of the YEC, CAFN, external stakeholders, and public related to the use of Aishihik Lake.

(b), **(c)**, **(d)** and **(e)**

As noted, the $7.918 million cost provided in Appendix 5.3 of the Application relates to forecast costs only to the end of 2021. Appendix 5.3 noted that the project is now forecast to be complete by end of 2022.

Table 2 below compares:

(a) the forecast cost breakdown provided during the 2017/18 GRA[1] to complete the 25-year licence renewal; and
(b) the updated forecast costs to complete this project by the end of 2022.

The updated forecast costs of $9,388,758 to complete the project include 2020 and 2021 costs that are $0.871 million higher than the forecast reviewed in Appendix 5.3 of the 2021 GRA (see Table 1 above) plus $600,000 forecast costs for 2022 (the 2021 GRA did not provide any forecast for this project's costs after 2021).

[1] The response to YUB-YEC-1-77(a) in the 2017-18 GRA proceeding provided a cost breakdown for $3.149 million, excluding compensation costs to CAFN. Table 2 includes the added $0.42 million (as required for the $3.569 million 2017-18 GRA forecast) under CAFN Compensation and Stakeholder Engagement.

Table 2: 2017/18 GRA Forecast compared to Updated Forecast to end of 2022 – Aishihik Relicensing Project Costs

	Forecast cost to end of 2022	2017/18 GRA Forecast Cost Sept, 2015 budget	Variance	Cost Drivers
Project Management	$730,460	$553,000	$177,460	Additional project management required to provide project management services over extended project timeline and coordinate/attend increased number of technical subgroups.
CAFN Compensation & Stakeholder Engagement	$2,145,503	$804,000	$1,761,083	$500,000 Chemi Narrows compensation payment (requirement from 2002 relicensing process, adjusted to this compensation in the Three Year Licence) was not included in initial budget. Significant additional engagement and collaboration requirements beyond those anticipated in the initial budget, including increased capacity funding for CAFN.
Impact Assessment Studies	$4,249,722	$1,759,000	$2,490,722	Additional studies and technical work beyond that anticipated in the initial budget. drove higher costs, particularly during shared study planning process with CAFN plus added costs due to extended time for studies.
Early Monitoring	$564,949	$-	$564,949	Engagement with CAFN and YG revealed requirement for early monitoring programs (as well as requirements from 3-year license to support 25-year renewal) not anticipated in the initial budget. Some items raised for consideration or requested by external parties to be part of the MAMP were required to be piloted to ensure commitments over long term are effective and achievable. In order to address assessment and permitting risk, elements initiated to evaluate impact for

				the long-term license requirements.
Permitting processes	$1,001,690	$300,000	$701,690	Collaborative approach with external parties as directed in Three Year Licence drove an increase in the MAMP scope. Specific information on the MAMP is required for the Water Board; accordingly, scope increases drove additional supporting technical work to complete the processes.
Aishihik Advisory Committee	$196,434	$153,000	$43,434	Increased scope of committee activities per input from committee members; Additional accrual of AFUDC due to project extended timeline.
2021 & 2022 AFUDC	$500,000	$-	$500,000	Additional accrual of AFUDC due to project extended timeline and increased budget.
Project Total:	**$9,388,758**	**$3,569,000**	**$6,239,338**	

Explanation as to why the total cost has increased as described in Table 2, and why the initial cost estimate provided in the 2017-18 GRA was less than half the current estimate, requires review of the context for the 2017-18 GRA forecast including Champagne and Aishihik First Nations' (CAFN) historic grievances relating to the facility and other key factors affecting the relicensing of the Aishihik Generating Station.

Background re: 2017-18 Cost Forecast

The 2017-18 GRA filing addressed a project that was to remain in WIP for the test years and therefore did not affect the revenue requirement during the test years. When the GRA was filed in June 2017, the relicensing process was still at an early stage of development. The forecast cost provided in the GRA reflected a preliminary budget approved by the YEC Board in September 2015.

However, the 2017-18 GRA filing noted that the last Aishihik licence renewal (2002) cost approximated $8.791 million. That cost reflected protracted processes related to stakeholder engagement, first nation compensation, environmental assessment, and the Yukon Water Board. These processes underscored major issues CAFN had with the Aishihik facility dating back well before Yukon Energy acquired these assets from Canada in 1987.

The initial 2015 budget assumed that these issues would not once again cause similar protracted time and cost problems if a shared work plan approach for the relicensing assessment studies was adopted between Yukon Energy and CAFN (and other stakeholders).

In that regard, the 2017-18 GRA filing recognized that the Aishihik hydro facility has had long term impacts on CAFN, that Yukon Energy and CAFN were working in partnership on proposed terms and conditions for the new Aishihik water license, and that in January of 2016 Yukon Energy and CAFN entered into a Protocol Agreement which established shared objectives, procedures and governance of the new relationship.

During the 2017/2018 GRA Application process, when YEC forecast the project to be completed by the end of 2019 (when the then existing water use licence expired), YEC identified in YUB-YEC-1-77 that the forecast costs could not be accurately estimated at the time given the material uncertainties relating to the First Nation and regulatory issues surrounding this project. This was clearly articulated as follows:

> "Largely due to the known increased quantum and scope of the impact assessment studies required for the project proposal to YESAB, as well as the funding of the CACAC and CAFN traditional knowledge project, the project is expected to exceed the initial budget of $3.569 million. Due to unknown costs related to potential increase in the scope of regulatory proceedings, and compensation to the CAFN, the final project cost cannot be accurately estimated at this time. YEC will continue to monitor the development of costs related to unknowns and adjust the budget accordingly."

Experience during 2017 through 2018 confirmed that the uncertainties and issues surrounding this project since its inception remained. It became evident during this time that considerably more time and costs would be required than forecast in the initial budget. This experience revealed amongst other things the challenges that CAFN and YEC faced in trying to carry out the shared work plan.

As reviewed below - because of these difficulties and other related matters --, Yukon Energy had to suspend its 25 year relicensing project in early 2019 in order to secure a three year licence renewal while reconciliation discussions between the Yukon government and CAFN relating to amongst other things CAFN's historical grievances were ongoing.

Overview of Key Factors for Cost & Schedule Change

In summary, the two key factors accounting for the added time and cost requirements for this project are:

- The long-standing concerns of Champagne and Aishihik First Nations (CAFN) with regard to this facility's origins and ongoing impacts; and

- The Yukon Government's decision by early 2019 to engage in negotiation of an agreement with CAFN to address issues of concern including reconciliation.

Overlaying the above key factors is the critical importance of the AGS facility (and its successful relicensing) for the Yukon Integrated System and the strong interest that Yukon Energy has in establishing an improved long-term relationship with CAFN. See Appendix A to this response for summary of the key features of the Aishihik facility.

CAFN's Longstanding Concerns

Yukon Energy was aware of CAFN's long standing and ongoing concerns related to the AGS. These concerns were front and center in the 2002 renewal process and they have not abated.

To try to deal with these issues -- at the start of the current AGS relicensing in 2016 -- Yukon Energy and CAFN worked together to develop a shared work plan for the AGS long term licence renewal through implementation of a Protocol Agreement.

- Through the Protocol Agreement the parties agreed to work together, on a without prejudice basis, to pursue common objectives for the AGS Water Licence renewal.

- The Protocol Agreement (2016) did not expand CAFN's rights under the Final Agreement, but it confirmed that CAFN retained the right to participate freely in the regulatory review and Government consultation processes (i.e., under *YESAA* and the *Waters Act*) and to oppose any or all parts of what may be proposed.

- The shared work planning process provided a framework for extensive engagement with CAFN and other relevant stakeholders that commenced in 2016 and extended throughout the Project planning phase until the fall of 2018. This

included Yukon Energy and CAFN working jointly to direct the consulting team regarding the Project work plan and schedule, including the scope of the baseline studies, a structured decision making process to jointly attempt to determine a preferred operating regime, and the opportunity to review and comment on initial Project Proposal draft documentation.

- The shared work planning process under the Protocol Agreement ended in October 2018 as the parties were unable to obtain consensus regarding the operating range for Aishihik Lake. Due to the impending licence renewal deadline Yukon Energy proceeded with preparing and filing a YESAA Project Proposal that reflected key elements of Water Use Licence HY99-011. CAFN indicated that it was not in agreement with Yukon Energy's decision to move ahead with its preferred operating alternative.

The above experience between 2016 and the end of 2018 resulted in a greatly expanded and prolonged impact assessment study and CAFN engagement processes that delayed initiation of required YESAA evaluation and subsequent permitting activities. YEC attempted to move ahead by the start of 2019 with its 25-year YESAA Project Proposal – but - as outlined below - work on this project had to be deferred to address a three-year short-term relicensing project.

Yukon Government Reconciliation Discussions – Three Year Licence

Yukon Energy brought forward the AGS Relicensing Project Proposal in February 2019 for a three-year renewal term. This was done to allow the YG and YEC to engage with CAFN on reconciliation related issues including historic grievances CAFN had with the Aishihik facility and to avoid a lapse in Yukon Energy's water use licence for the AGS and termination of Yukon's encumbering rights related to this project under the CAFN Final Agreement.[2]

The three year licence approved by the Yukon Water Board in early 2020 outlined a number of additional regulatory requirements for the 2020-2022 period that have driven added costs for completion of the long-term relicensing project. The regulatory requirements included: additional collaborative monitoring and studies during the three

[2] Due to delays in filing the YESAA Project Proposal to accommodate Yukon Government discussions with Champagne and Aishihik First Nations (CAFN), Yukon Energy had to address material risks that the regulatory review timelines could extend beyond 2019.

year licence; development of a collaborative downstream monitoring and adaptive management plan; and reporting on collaboration with CAFN and other parties in relation to the required monitoring and adaptive management specified in the licence.

After the three year licence renewal was secured in early 2020, Yukon Energy engaged in a further collaborative process with CAFN and YG to develop a Monitoring and Adaptive Management Plan (MAMP) for the long-term licence renewal. Concurrently, CAFN, YG and Yukon Energy continue to work on concluding a reconciliation agreement to address long-standing issues of mutual interest. These activities were also not anticipated in the initial September 2015 project budget, and result in further material schedule extensions and cost increases.

At the time of filing this IR response, negotiations for the reconciliation agreement have substantively progressed, but have yet to be concluded.

In summary, the use of a collaborative process with CAFN from 2016 to 2018, prior to the 2019 filing and over 2020 and 2021 has led to very material increases in effort and related costs to date and a significantly longer process than originally envisioned.

The only way to reduce costs would have been to reduce the level of collaboration with CAFN regarding the relicensing process and avoid the 3-year renewal requirement by completing the 25-year relicensing proposal in accordance with the initial schedule. However, in the context of the Water Use Licence and a Yukon government led agreement process with CAFN related to this project and other outstanding issues, this was not feasible – and any such option would not have had any assurance that the end result would have secured the required licence.

YEC plans to conduct a comprehensive ‘lessons learned’ analysis prior to the initiation of similar future relicensing projects in order to increase the estimation of project costs by increasing the accuracy of estimated technical effort and engagement requirements.

Appendix A: Importance of AGS for the Yukon Integrated System

The Aishihik Generating Station (AGS) is a critical asset for the Yukon Integrated System (YIS); and ensuring that the regulatory instruments required for its ongoing operation are sustained is an essential requirement and responsibility for Yukon Energy.

- The AGS provides the only material annual storage in the Yukon and load following power, after non-dispatchable generation resources (e.g., any existing wind or run-of-river hydro generation facilities) have been utilized.

- Under long-term average water conditions, the AGS supplies approximately 25% of the total annual YIS generation – and about 40% of annual YIS winter generation concentrated in the months from November through May when peak YIS loads occur and run-of-river hydro supplies are constrained.

- The AGS also provides 37 MW of dependable capacity[3] to the YIS, which is more than one quarter of Yukon Energy's maximum generation capacity.

- Cessation or reduction of AGS operation would require that the current generation capability of AGS be replaced with some other source of energy that could be relied upon during the winter months. No such renewable alternative is in place today.

- Prior to planning, permitting and development of any new alternative generation capability, including renewable supply options, YEC would need to rely on existing thermal generation to replace the energy supplied currently by the AGS. Reliance on thermal generation to replace AGS hydro generation would have ongoing and very significant added generation operation costs (for fuel and non-fuel O&M) as well as added GHG emissions.[4]

[3] Dependable capacity, expressed in MW, is the maximum generation output that a resource can reliably provide in a specific timeframe, typically during the period of greatest demand. YEC defines dependable capacity as the maximum output that a resource can reliably provide over two consecutive weeks during the four winter months (November to February) based on the inflows in the five driest inflow years in history.

[4] Implications are discussed at a high level in Appendix 6C of YEC's 2020 YESAB Project Proposal, which provides estimates of added capital and O&M costs as well as added GHG emissions associated with an alternative (Alternative 7) that removes AGS storage capability as proposed by CAFN and limits operating to the pre AGS Aishihik Lake LSL and FSL levels, i.e., the high added capital costs (+$100 million), O&M costs (~$12 million per year long-term average for thermal generation) and GHG emissions (+32 kt/year CO2e long-term average) for this alternative compared with the existing licence under 2021 grid loads and grid configuration which still retains run-of-river hydro generation benefits from the AGS.

- Yukon Energy assessments also indicate that the 37 MW of AGS dependable capacity would also likely need to be replaced with new thermal generation capacity in order to maintain dependable winter supply capability, which would require time for planning and permitting and a capital cost for new thermal generation capacity in excess of $100 million (a significantly higher capital cost would be required for similar new dependable renewable capacity even if such an alternative was available in the near to medium term).

In light of the above considerations, renewal of the AGS water use licence under terms substantially similar to the 2002 water use licence has been (and continues to be) considered the only reasonable option for Yukon Energy to pursue at this time.

REFERENCE: **Application, PDF pages 151-152, Table 5.7, 2021-2024, Energy Storage System**

ISSUE: Work-in-progress continuity schedules – Battery Energy Storage System and related Contribution

QUOTE: PDF pages 151-152, [excerpt of] Energy Storage System financial information:

YUKON ENERGY CORPORATION 2023/24 GRA — Table 5.7
WORK IN PROGRESS CONTINUITY SCHEDULE - Projects Not impacting Rate Base — August 2023
($000S)

	2021				2022			
	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance
Capital Projects – Major projects > $1 million – Not impacting Rate Base								
Energy Storage System	517.4	854.5	-219.5	1,152.4	1,152.4	8,848.3	0.0	10,000.7
Energy Storage System Contributions	-316.2	-581.3	0.0	-897.5	-897.5	-6,128.6	0.0	-7,026.1

	2023				2024			
	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance	WIP Opening Balance	Expenditures	Adjustments	WIP Closing Balance
Capital Projects – Major projects > $1 million – Not impacting Rate Base								
Energy Storage System	10,000.7	19,950.0	0.0	29,950.7	29,950.7	1,000.0	0.0	30,950.7
Energy Storage System Contributions	-7,026.1	-9,473.9	0.0	-16,500.0	-16,500.0	0.0	0.0	-16,500.0

PREAMBLE: The Board requires an update of the BESS project.

QUESTION:

a) Please provide an update of the current status of the BESS project including any changes in: project scope, forecast, or actual costs incurred to date, anticipated in-service dates, or other pertinent details since YEC's last GRA.

b) Please prepare a table comprised of major cost components with totals to each closing work-in-progress (WIP) balance noted in the quote above for each of the years 2021 through 2024.

c) Please clarify whether the contribution amount is expected to change in step with the forecast capital costs. Why or why not?

ANSWER:

(a)

Please see response to YUB-YEC-1-44. A summary of project expenditures to the end of September 30, 2023 and the updated project forecast at completion are provided in the table below.

Category	Costs to End Quarter ($000's)	Forecast at Completion ($000's)
EPC Contractor	$11,069	$30,427
Engineering	$754	$755
Project Management	$485	$1,019
YEC Internal	$357	$845
Owners Engineer	$429	$890
Assessment and Permitting	$204	$243
Transmission Line	$136	$160
Engagement	$138	$288
AFUDC	$406	$895
Subtotal	$13,978	$35,522
Contingency	$0	$325
Total	$13,978	$35,847

(b)

Table below provides annual expenditures by major components of the figures provided in the Application, Table 5.7. The table below excludes expenditures of $517.4k prior to 2021, as noted in Table 5.7 of the Application.

Cost Component	2021	2022	2023	2024
EPC Contractor	-	8,068,273.72	17,829,251.76	550,000.00
Engineering	446,906.97	68,955.69	17,097.30	-
Project Management	71,864.82	195,725.04	823,825.16	200,000.00
YEC Internal	45,289.26	122,292.21	594,487.06	100,000.00
Owner's Engineer	-	191,822.71	534,560.42	150,000.00
Part 3 Defence	219,518.69	-	-	-
Assessment & Permitting	64,856.78	44,765.24	43,821.30	-
Transmission Line	-	130,061.61	29,761.60	-
Engagement	6,110.33	26,380.34	77,195.40	-
Grand Total	**854,546.85**	**8,848,276.56**	**19,950,000.00**	**1,000,000.00**

(c)

Contributions are not expected to change in step with forecast costs as certain costs are not eligible and total contributions are capped at $16.5M.

REFERENCE: **Application, PDF page 149, Table 5.6, Summary of Completed Projects for 2021-2024 Years**

ISSUE: Deferred project costs

QUOTE:

YUKON ENERGY CORPORATION 2023/24 GRA					Table 5.6
SUMMARY OF COMPLETED PROJECTS FOR 2021-2024 YEARS					August 2023
($000S)					
	Completed Projects ($000)				
	2021	2022	2023	2024	Total
Deferred Costs – Major projects > $1 million – Rate Base Additions					
DSM Program Development	10.4	1,430.8	-	-	1,441.2
DSM Program Development Contributions	-	(1,141.6)	(21.6)	-	(1,163.3)
DSM Program 2022-2030	-	64.2	1,271.6	1,160.0	2,495.9
Southern Lakes Storage	-	-	8,784.2	-	8,784.2
Aishihik 5-Year License Renewal	-	3,903.4	575.4	-	4,478.8
Subtotal	**10.4**	**4,256.8**	**10,609.5**	**1,160.0**	**16,036.7**
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions					
IPP Standing Offer Program Implementation	326.0	-	70.3	-	396.3
Dam Safety Review	254.5	-	-	-	254.5
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	-	-	385.6	-	385.6
Mayo Civil Infrastructure Refurbishment Planning	-	-	168.4	-	168.4
System Wide Arc Flash Study	-	-	197.7	-	197.7
Whitehorse Post-Flood Assessment	-	115.2	-	-	115.2
WRGS Thermal Assessment & Permitting	-	-	-	413.0	413.0
Public Safety Plans	-	-	225.0	-	225.0
System Wide Stability Study	-	-	200.0	-	200.0
Digital Strategy and Policy Development	-	-	120.0	-	120.0
Privacy Management Program	-	-	100.0	-	100.0
Vegetation Management Plan Update	-	-	225.0	-	225.0
Cyber Security Framework	-	-	-	140.0	140.0
Transmission Line Detailed Inspection Program	-	-	-	250.0	250.0
Gates/TIV's Certification Assessment System Wide	-	-	-	200.0	200.0
Digital Reporting Review	-	-	-	125.0	125.0
Records Policy Planning and Program Development	-	-	-	100.0	100.0
Breaker Condition Assessment	-	-	-	100.0	100.0
Other Projects with <$100k Spending	262.8	172.6	342.2	(10.0)	767.6
Subtotal	**843.3**	**287.9**	**2,034.2**	**1,318.0**	**4,483.3**

PREAMBLE: YEC's Application separates deferred project costs into two categories: Major projects > $1 million and Projects $100,000 to $1 million.

QUESTION:

a) Please provide references to past YEC decisions indicating the Board's preference for the capitalization of the various studies, assessments, reviews, and similar as opposed to expensing them in the year the expenses are incurred.

b) Does YEC recover AFUDC on the various studies, assessments, reviews, and similar during the time they remain in CWIP as deferred costs?

c) Does YEC recover a return on rate base on the unamortized portion of the various studies, assessments, reviews, and similar?

d) How and when is the decision made by YEC to "capitalize" the deferred costs into rate base either on a stand-alone basis or as part of the costs of a larger project?

e) How does the capitalization of the various studies, assessments, reviews, and similar meet YEC's test for capitalization under YEC's capitalization policy?

f) Please provide a copy of YEC's capitalization policy as support for its response to part (e).

g) Please prepare a table of all deferred project costs from 2021 to 2024 as identified in the quote above and add a column explaining how each of the projects met or will meet YEC's test for capitalization under YEC's capitalization policy.

ANSWER:

(a)

In YEC's last GRA, for the test year 2021, the Board approved capitalization of deferred costs for rate regulation purposes as provided in Section 5.3 of that Application. This has been the practice in prior GRAs for deferred cost projects (i.e., planning and study costs, regulatory and licensing activities, and dam safety reviews), reflecting the fact that these costs relate to long-term services rather test year services. Capitalization of deferred costs is also consistent with the Planning Cost Accounting Policy the Board approved in YUB Order 2018-10, Appendix A, paragraph 540. YEC is not aware of the Board raising

questions in past YEC decisions regarding any option of expensing these costs in the year the expenses are incurred.

(b)

Projects are charged AFUDC when there are costs incurred until project completion. However, recovery of AFUDC, like all other project costs, does not occur until the project is in-service – and recovery of AFUDC through rates requires a decision of the Board.

(c)

Yes, YEC recovers a return on the unamortized portion of all projects approved in rate base.

(d)

Generally, YEC capitalizes the deferred costs as part of a larger project if there is a direct link from the deferred costs to the larger project and the larger project is or will be completed. However, if the deferred costs are insignificant or do not result in completing a larger project, these costs could be capitalized on a stand-alone basis.

(e) and (f)

YEC uses separate guidelines for non-tangible assets, YEC's Finance Accounting Practice FX-005 (Feasibility Studies and Regulatory Requirements) and FX-008 (Intangible Assets). They are consistent with the Planning Cost Accounting Policy the Board approved in YUB Order 2018-10, Appendix A, paragraph 540. These guidelines are attached (see YUB-YEC-1-63(f) Attachment 1 and YUB-YEC-1-63(f) Attachment 2). YEC's accounting treatment is audited annually by the Office of the Auditor General of Canada.

(g)

Please see the table that follows.

	2021	2022	2023	2024	Total		Relevant Policy/Practice	
Deferred Costs – Major projects > $1 million – Rate Base Additions								
DSM Program Development	10.4	1,430.8	-	-	1,441.2		FX-005	Regulatory requirement
DSM Program Development Contributions	-	(1,141.6)	(21.6)	-	(1,163.3)		FX-005	Regulatory requirement
DSM Program 2022-2030	-	64.2	1,271.6	1,160.0	2,495.9		FX-005	Regulatory requirement
Southern Lakes Storage	-	-	8,784.2	-	8,784.2		FX-005	Feasibility Study
Aishihik 5-Year License Renewal	-	3,903.4	575.4	-	4,478.8		FX-008	Intangible Asset/Water License
Subtotal	**10.4**	**4,256.8**	**10,609.5**	**1,160.0**	**16,036.7**			
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions								
IPP Standing Offer Program Implementation	326.0	-	70.3	-	396.3		FX-008	Intangible Asset/Program
Dam Safety Review	254.5	-	-	-	254.5		FX-005	Feasibility Study
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	-	-	385.6	-	385.6		FX-005	Regulatory requirement
Mayo Civil Infrastructure Refurbishment Planning	-	-	168.4	-	168.4		FX-005	Feasibility Study
System Wide Arc Flash Study	-	-	197.7	-	197.7		FX-005	Feasibility Study
Whitehorse Post-Flood Assessment	-	115.2	-	-	115.2		FX-005	Feasibility Study
WRGS Thermal Assessment & Permitting	-	-	-	413.0	413.0		FX-005	Feasibility Study
Public Safety Plans	-	-	225.0	-	225.0		FX-005	Feasibility Study
System Wide Stability Study	-	-	200.0	-	200.0		FX-005	Feasibility Study
Digital Strategy and Policy Development	-	-	120.0	-	120.0		FX-005	Feasibility Study
Privacy Management Program	-	-	100.0	-	100.0		FX-008	Intangible Asset/Program
Vegetation Management Plan Update	-	-	225.0	-	225.0		FX-005	Feasibility Study
Cyber Security Framework	-	-	-	140.0	140.0		FX-005	Feasibility Study
Transmission Line Detailed Inspection Program	-	-	-	250.0	250.0		FX-008	Intangible Asset/Program
Gates/TIV's Certification Assessment System Wide	-	-	-	200.0	200.0		FX-008	Intangible Asset/Certification
Digital Reporting Review	-	-	-	125.0	125.0		FX-005	Feasibility Study
Records Policy Planning and Program Development	-	-	-	100.0	100.0		FX-008	Intangible Asset/Program
Breaker Condition Assessment	-	-	-	100.0	100.0		FX-005	Feasibility Study
Other Projects with <$100k Spending	262.8	172.6	342.2	(10.0)	767.6		FX-005	Not material
Subtotal	**843.3**	**287.9**	**2,034.2**	**1,318.0**	**4,483.3**			

1

YUKON ENERGY	Finance Accounting Practice FX-005	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Feasibility Studies and Regulatory Requirements

1.0 Purpose

To provide guidelines for capitalization and amortization of study costs.

2.0 Feasibility Studies and Infrastructure Planning

Planning and Feasibility Studies are undertaken to determine the feasibility of a range of projects and infrastructure proposals. The costs will be capitalized and included in Regulatory Deferred Accounts. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

3.0 Where a determination is made that a fixed asset project will be constructed, the related study job will be held in WIP until the fixed asset project is completed. After the project is completed, the related studies jobs shall be closed as Feasibility studies assets and amortized on the same basis as the related assets. Exceptions to this practice are when the costs are not material.

4.0 If the project does not proceed, the studies jobs shall be closed as Feasibility studies assets, and the costs shall be amortized as follows:

a. Where accumulated costs are less than $1 million – the planning and studies costs will be amortized over five years.
b. Where accumulated costs have exceeded $1 million – the planning and studies costs will be amortized over ten years.

5.0 Where a project is driven by regulatory requirement, it will be under regulatory category.

YUKON ENERGY	Finance Accounting Practice FX-008	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		All	Finance	Intangible Assets

1.0 Purpose

To provide guidelines for intangible assets. Sources used are IAS 38 Intangible Assets.

2.0 Definition

An intangible asset is an identifiable non-monetary asset without physical substance. Such an asset is identifiable when it is separable, or when it arises from contractual or other legal rights. Separable assets can be sold, transferred, licensed, etc. Examples of intangible assets include computer software, licenses and certifications, etc.

3.0 Recognition

An intangible asset shall be recognised if, and only if:
(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and
(b) the cost of the asset can be measured reliably.

4.0 Licenses, Programs and Certifications

Water Licensing are capitalized and amortized over the estimated useful life.
If certifications have future benefits that last beyond the year in which the costs are incurred, they will be capitalized and amortized over the estimated useful life.

5.0 Computer Software

When the software is not an integral part of the related hardware, computer software is treated as an intangible asset. If computer software is purchased with the initial purchase of new computer hardware as an integral part then the software is capitalized with the cost of the computer hardware as PPE.

In-house software development (costs related to the direct and indirect design, programming, testing, and implementation costs for new applications) and enhancement (costs related to the direct and indirect design, programming, testing and implementation costs for improvements to an existing system) projects including implementation and testing costs for packaged products costing in excess of $1,000 are capitalized and amortized over the estimated useful life of the software package. Financial system software normally will have 10 years life.

No intangible asset arising from research (or from the research phase of an internal project) shall be recognized. In the research phase of an internal project, an entity cannot demonstrate that an intangible asset exists that will generate

probable future economic benefits; It will be treated as feasibility studies (refer to FX-005 Feasibility studies).

REFERENCE: **Application PDF pages 496-499, Schedule 3A-2023 and Schedule 3A-2024; PDF pages 145-148, Table 5.4-2023 and Table 5.5-2024; PDF pages 151-152, Table 5-7**

ISSUE: Capital related schedules

PREAMBLE: The Board seeks to understand the relationships between the various schedules provided by YEC.

QUESTION:

a) With respect to capital additions for each of 2023 and 2024, please reconcile the capital additions on PDF pages 496-497, Schedule 3A-2023, and PDF pages 498-499, Schedule 3A--2024, with the capital additions for completed projects on PDF pages 145-146, Table 5.4 2023 and PDF pages 147-148, Table 5.5-2024.

b) Please explain the difference between closing CWIP shown on PDF pages 145-146, Table 5.4-2023, and PDF pages 147-148, Table 5.5-2024, and the closing CWIP shown on PDF pages 151-152, Table 5-7.

c) Please explain why YEC appears to have separated closing CWIP where there are rate base additions from closing CWIP where there are no rate base additions notwithstanding, in YEC's 2021 GRA, in response to YEC-YUB-2-16, there was a single combined document provided.[1]

d) Please identify the tables in Tab 5 that YEC considers responsive to the Board direction at par. 242 of Appendix A to Board Order 2022-03.

e) Referring to Schedule 3A-2023 as an example, please provide a reason for the lines noted as "Depreciation Study Differences."

[1] Appendix A to Board Order 2022-03 stated the following at par. 242: "Due to these concerns, the Board directs YEC to present cost breakdowns for its capital projects in a uniform manner in future GRA proceedings. The Board further directs YEC to provide schedules for all capital projects in the CWIP continuity format — the template for which was provided in information request YUB-YEC-2-16 — in future GRA proceedings. In order to ensure a fair and efficient process for future GRAs, if YEC does not comply with this direction, the Board may request YEC to update and refile its application or may deny the application."

f) Referring to Schedule 3A-2023 as an example, how does YEC distinguish between the Land account identified as “Rights” which is amortized over 50 years from the account identified reflects the amount of $0.113 million of forecast amortization expense for 2023?

ANSWER:

(a)

Please see YUB-YEC-1-64 Attachment 1 for reconciliation between Tables 5.4 and 5.5 of Tab 5 and Schedules 3A and 3B of Tab 7.

(b)

The closing CWIP balances shown on PDF pages 145-146, Table 5.4-2023, and PDF pages 147-148, Table 5.5-2024 reflect the CWIP balances of projects that impact the rate base [the portion left in CWIP after partial closing shown in the tables], while the closing CWIP shown on PDF pages 151-152, Table 5-7 reflect the CWIP balances for the projects that do not impact the rate base. They do not reconcile but are added together to get the total CWIP balances in Table 5.1.

Please see YUB-YEC-1-64 Attachment 2 which summarizes CWIP balances and reconciles to Table 5.1.

(c) and (d)

The YUB in its Order 2022-03 directed YEC to provide schedules for all capital projects in the CWIP continuity format, the template for which was provided in information request YUB-YEC-2-16 from the 2021 GRA, in future GRAs. Based on this direction, YEC revised the format of Tab 5 tables [Tables 5.2 through 5.5, and Table 5.7] so they are consistent with the template provided in YUB-YEC-2-16 from the 2021 GRA. These tables are consistent with the YUB-YEC-2-16 and the YUB directive [shows the opening CWIP balance at the beginning of the year, capital spending, close-outs/adjustments, and the closing CWIP balance].

YEC has separated the capital projects that do not impact the rate base or revenue requirements for the 2023 and 2024 test years [Table 5.7] from those that impact the

revenue requirements [Tables 5.2 through 5.5]. A similar approach was taken in the 2021 GRA, and YUB in its Order 2022-03, paragraph 337 stated with regard to project costs remaining in WIP that "[g]iven that the costs for the projects in this category do not affect the test year rate base or revenue requirement, the Board makes no findings regarding these projects at this time."

(e)

"Depreciation Study Differences" are the amortization of reserve differences true-up that were reviewed as part of the 2021 GRA as updated based on Board direction provided in Order 2022-03 paragraph 148.

(f)

The "Right of Use Assets" in Schedule 3A reflects the capital lease of land while land rights are the rights owned by YEC.

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 1

Tab 5, Table 5.4

Category of capital project	Completed Projects	Function
Capital Projects – Major projects > $1 million – Rate Base Additions		
Thermal Replacement (16.5 MW)	0.0	Diesel
Whitehorse Interconnection	0.0	Main Transmission
Whitehorse Stoplog Crane Replacement	4,246.7	Buildings & Equipment
MH0 Road & Road Slope Stability	1,874.4	Hydro
Transmission Line Replacement L178	1,000.0	Main Transmission
2023 Mayo-Faro Diesel Infrastructure	4,300.0	Diesel
P&C: S250 Callison Protection, Control and SCADA Upgrad	2,124.9	Main Transmission
Dawson Voltage Conversion	0.0	Distribution
Wareham Spillway Concrete Repair	500.0	Hydro
Schwatka Lake Safety/Debris Boom	1,096.8	Hydro
Subtotal	**15,142.7**	
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions		
Generation		
MBH1/2 Seal Water Filtration	285.7	Hydro
Other Projects with <$100k Spending	255.7	183.5 Hydro, 52 Diesel, 20.2 LNG
Subtotal	**541.4**	
Transmission		
P&C: S170 Protection, Control and SCADA Upgrade	0.0	Main Transmission
L177 Re Route	738.3	Main Transmission
L177 Re Route Contributions	-433.6	Maintenance Contibutions
NWTEL Make Ready Work	175.0	Main Transmission
Other Projects with <$100k Spending	104.4	Main Transmission
Subtotal	**584.1**	
Distribution		
Customer Extensions	1,727.1	Distribution
Customer Extensions Customer Contributions	-1,260.7	Maintenance Contibutions
IPP Connections	5,205.3	Distribution
IPP Connections Customer Contributions	-6,400.9	Maintenance Contibutions
Synchronous Condenser Overhaul	616.3	Distribution
Dawson Distribution 3 Phase Loop	350.0	Distribution
Other Projects with <$100k Spending	150.0	Distribution
Subtotal	**387.0**	
General Plant		
New Mobile Office Unit - IT	810.2	Buildings & Equipment
Vehicle Purchases	623.8	Transportation
Compact Digger Truck	200.4	Transportation
Skid Steer	189.0	Transportation
Mayo-McQuesten Radio to Fiber Migration	134.6	Buildings & Equipment
Waste Management Equipment	110.0	Buildings & Equipment
HQ Datacenter Server Replacement	0.0	Buildings & Equipment
SCADA Operation Network Segregation	0.0	Buildings & Equipment
Other Projects with <$100k Spending	727.5	692.5 Buildings & Equipment, 35 Transportation
Subtotal	**2,795.6**	
Overhaul		
AH1 10 Year Overhaul	2,461.0	Hydro
WG1 Overhaul	400.0	LNG
WG2 Overhaul	400.0	LNG
Subtotal	**3,261.0**	
Right of Use Assets		
Right of Use Asset 1 Lindeman Road	750.1	Right of Use Kulan Land
Subtotal	**750.1**	
RFID		
RFID	899.9	Uninsured Loss Projects
Subtotal	**899.9**	

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 1

Tab 5, Table 5.4

Category of capital project	Completed Projects	Function
Reserve for Site Restoration		
Reserve for Site Restoration Bucket	763.1	RFSR Main Transmission
Subtotal	**763.1**	
Deferred Costs – Major projects > $1 million – Rate Base Additions		
DSM Program 2022-2030	1,271.6	Regulatory
DSM Program Development Contributions	-21.6	Regulatory
Southern Lakes Storage	8,784.2	Feasibility
Aishihik 5-Year License Renewal	575.4	Licensing
Subtotal	**10,609.5**	
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions		
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	385.6	Regulatory
WRGS Thermal Assessment & Permitting	0.0	Licensing
Public Safety Plans	225.0	Feasibility
System Wide Stability Study	200.0	Feasibility
System Wide Arc Flash Study	197.7	Feasibility
Mayo Civil Infrastructure Refurbishment Planning	168.4	Feasibility
Digital Strategy and Policy Development	120.0	Feasibility
Privacy Management Program	100.0	Feasibility
Vegetation Management Plan Update	225.0	Feasibility
IPP Standing Offer Program Implementation	70.3	Feasibility
		319 Feasibility, 23.1
Other Projects with <$100k Spending	342.2	Regulatory
Subtotal	**2,034.2**	
Intangible Assets – Major projects > $1 million - Rate Base Additions		
PAMMS Asset Management Framework	5,466.2	Intangible
Subtotal	**5,466.2**	
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions		
Network Software Traffic Shaping	250.0	Intangible
CIS Replacement	118.3	Intangible
Other Projects with <$100k Spending	72.8	Intangible
Subtotal	**441.1**	
Total	**43,676.0**	

	Table 5.4	Schedule 3A - 2023	Variance
Hydro	6,401.3	6,401.3	0.0
Diesel	4,352.0	4,352.0	0.0
Main Transmission	4,142.6	4,142.6	0.0
Distribution	8,048.6	8,048.6	0.0
Buildings & Equipment	5,994.1	5,994.1	0.0
Transportation	1,048.3	1,048.3	0.0
LNG	820.2	820.2	0.0
Right of Use Kulan Land	750.1	750.1	0.0
Total	31,557.2	31,557.2	

	Table 5.4	Schedule 3B - 2023	
Feasibility	10,409.6	10,409.6	0.0
Regulatory	1,658.8	1,658.8	0.0
Licensing	575.4	575.4	0.0
Intangible	5,907.3	5,907.3	0.0
Total	18,551.0	18,551.0	

Maintenance Contibutions	(8,095.2)	Contributions
Uninsured Loss Projects	899.9	Transfer to RFID
RFSR Main Transmission	763.1	Transfer to RFSR

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 1

Tab 5, Table 5.5

Category of capital project	Completed Projects	Function
Capital Projects – Major projects > $1 million – Rate Base Additions		
Thermal Replacement (16.5 MW)	18,175.5	Diesel
Whitehorse Interconnection	11,198.9	Main Transmission
Transmission Line Replacement L178	5,000.0	Main Transmission
Dawson Voltage Conversion	1,871.8	Distribution
Whitehorse Spillway Stoplog Refurbishment	1,000.0	Hydro
Lewes River Boat Lock Road Access Rebuild	1,200.0	Buildings & Equipment
Subtotal	**38,446.1**	
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions		
Generation		
WH4 Air Admission Valve Automation	200.0	Hydro
WG2 Cylinder Heads Swap	500.0	LNG
WG1 Radiator Replacement	300.0	LNG
Other Projects with <$100k Spending	75.0	50 Diesel, 25 Hydro
Subtotal	**1,075.0**	
Transmission		
P&C: S170 Protection, Control and SCADA Upgrade	839.0	Main Transmission
L177 Gang Switches	250.0	Main Transmission
Transmission Line Test and Treat Program 2020-22	250.0	Main Transmission
Other Projects with <$100k Spending	145.0	95 Main Transmission, 50 Sub Transmission
Subtotal	**1,484.0**	
Distribution		
Customer Extensions	600.0	Distribution
Customer Extensions Customer Contributions	-400.0	Maintenance Contibutions
Other Projects with <$100k Spending	155.0	Distribution
Subtotal	**355.0**	
General Plant		
Major Crane Assessment/Refurbishment	700.0	Buildings & Equipment
Vehicle Purchases	567.0	Transportation
HQ Datacenter Server Replacement	300.0	Buildings & Equipment
SCADA Operation Network Segregation	245.0	Buildings & Equipment
Other Projects with <$100k Spending	800.0	765 Buildings & Equipment, 35 Transportation
Subtotal	**2,612.0**	
Overhaul		
WG3 Overhaul	400.0	LNG
DD4 Overhaul	450.0	Diesel
Subtotal	**850.0**	
RFID		
RFID	681.7	Uninsured Loss Projects
Subtotal	**681.7**	

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 1

Tab 5, Table 5.5

Category of capital project	Completed Projects	Function
Deferred Costs – Major projects > $1 million – Rate Base Additions		
DSM Program 2022-2030	1,160.0	Regulatory
Subtotal	**1,160.0**	
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions		
WRGS Thermal Assessment & Permitting	413.0	Licensing
Cyber Security Framework	140.0	Feasibility
Transmission Line Detailed Inspection Program	250.0	Feasibility
Gates/TIV's Certification Assessment System Wide	200.0	Feasibility
Digital Reporting Review	125.0	Feasibility
Records Policy Planning and Program Development	100.0	Feasibility
Breaker Condition Assessment	100.0	Feasibility
Other Projects with <$100k Spending	-10.0	Feasibility
Subtotal	**1,318.0**	
Intangible Assets – Major projects > $1 million - Rate Base Additions		
Subtotal	**0.0**	
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions		
P&C Central Event Data Collection System	150.0	Intangible
SharePoint Upgrades	100.0	Intangible
Other Projects with <$100k Spending	130.0	Intangible
Subtotal	**380.0**	
Total	**48,361.8**	

	Table 5.5	Schedule 3A - 2024	Variance
Hydro	1,225.0	1,225.0	0.0
Diesel	18,675.5	18,675.5	0.0
Main Transmission	17,632.9	17,632.9	0.0
Sub Transmission	50.0	50.0	0.0
Distribution	2,626.8	2,626.8	0.0
Buildings & Equipment	3,210.0	3,210.0	0.0
Transportation	602.0	602.0	0.0
LNG	1,200.0	1,200.0	0.0
Total	**45,222.1**	**45,222.1**	

	Table 5.4	Schedule 3B - 2024	
Feasibility	905.0	905.0	0.0
Regulatory	1,160.0	1,410.0	(250.0)
Licensing	413.0	413.0	0.0
Intangible	380.0	380.0	0.0
Total	**2,858.0**	**3,108.0**	

Maintenance Contibutions	(400.0)	Contributions
Uninsured Loss Projects	681.7	Transfer to RFID

Note: The variance of $0.250 million under Regulatory reflects 2023/24 GRA spending which is forecast to remain in WIP by the end of 2024. There is no impact to the revenue requirements from this variance is $0.250 million is included under WIP and not included in rate base.

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 2

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Tab 5, Table 5.4				
Total Major Projects [before contributions]	16,999.4	44,461.2	-15,142.7	46,317.9
Maintenance Capital [before contributions]				
Total Generation	81.4	460.0	-541.4	0.0
Total Transmission	319.1	1,103.6	-1,017.7	405.0
Total Distribution	5,248.6	2,800.0	-8,048.6	0.0
Total General Plant & Equipment	339.6	2,596.1	-2,795.6	140.0
Capital Contributions	-5,761.6	-2,333.6	8,095.2	0.0
Right of Use Assets	0.0	750.1	-750.1	0.0
Total Overhaul	31.0	3,230.0	-3,261.0	0.0
Total Net RFID	345.9	554.0	-899.9	0.0
Total Net RFSR	40.1	723.0	-763.1	0.0
Deferred Costs [before contributions]	10,023.0	3,095.4	-12,665.4	453.0
Deferred Cost Contributions	0.0	-21.6	21.6	0.0
Intangible Assets	4,461.3	1,446.0	-5,907.3	0.0
Total	**32,127.8**	**58,864.2**	**-43,676.0**	**47,315.9**
Tab 5, Table 5.7				
Total Major Projects [before contributions]	10,462.1	24,102.0	0.0	34,564.1
Maintenance Capital [before contributions]				
Total Generation	156.7	60.0	0.0	216.7
Total Transmission	0.0	0.0	0.0	0.0
Total Distribution	0.0	0.0	0.0	0.0
Total General Plant & Equipment	0.0	0.0	0.0	0.0
Capital Contributions	-7,026.1	-9,473.9	0.0	-16,500.0
Deferred Costs [before contributions]	13,964.7	11,402.9	0.0	25,367.6
Deferred Cost Contributions	-288.5	0.0	0.0	-288.5
Intangible Assets	99.8	75.0	0.0	174.8
Total	**17,368.6**	**26,166.0**	**0.0**	**43,534.6**
Combined for 2023 Table 5.4 and Table 5.7				
Total Major Projects [before contributions]	27,461.5	68,563.2	-15,142.7	80,882.0
Maintenance Capital [before contributions]				
Total Generation	238.1	520.0	-541.4	216.7
Total Transmission	319.1	1,103.6	-1,017.7	405.0
Total Distribution	5,248.6	2,800.0	-8,048.6	0.0
Total General Plant & Equipment	339.6	2,596.1	-2,795.6	140.0
Capital Contributions	-12,787.7	-11,807.4	8,095.2	-16,500.0
Right of Use Assets	0.0	750.1	-750.1	0.0
Total Overhaul	31.0	3,230.0	-3,261.0	0.0
Total Net RFID	345.9	554.0	-899.9	0.0
Total Net RFSR	40.1	723.0	-763.1	0.0
Deferred Costs [before contributions]	23,987.7	14,498.2	-12,665.4	25,820.6
Deferred Cost Contributions	-288.5	-21.6	21.6	-288.5
Intangible Assets	4,561.1	1,521.0	-5,907.3	174.8
Total	**49,496.4**	**85,030.2**	**-43,676.0**	**90,850.5**
PP&E	34,023.8	80,840.0	(33,220.2)	81,643.7
Transfer to RFID/RFSR	386.0	1,277.0	(1,663.0)	-
Net PP&E	33,637.8	79,563.0	(31,557.2)	81,643.7
Table 5.1 [net of Transfer to RFID/RFSR]	33,637.8	79,563.0	(31,557.2)	81,643.7
Variance	-	-	-	-
Capital Contributions	(12,787.7)	(11,807.4)	8,095.2	(16,500.0)
Table 5.1	(12,787.7)	(11,807.4)	8,095.2	(16,500.0)
Variance	-	-	-	-

YEC 2023/24 GRA
YUB-YEC-1-64 Attachment 2

Category of capital project	Opening WIP	Capital Expenditures	Completed Projects	Closing WIP
Tab 5, Table 5.5				
Total Major Projects [before contributions]	46,317.9	21,900.0	-38,446.1	29,771.9
Maintenance Capital [before contributions]				
Total Generation	0.0	1,075.0	-1,075.0	0.0
Total Transmission	405.0	1,079.0	-1,484.0	0.0
Total Distribution	0.0	755.0	-755.0	0.0
Total General Plant & Equipment	140.0	2,472.0	-2,612.0	0.0
Capital Contributions	0.0	-400.0	400.0	0.0
Right of Use Assets	0.0	0.0	0.0	0.0
Total Overhaul	0.0	850.0	-850.0	0.0
Total Net RFID	0.0	681.7	-681.7	0.0
Total Net RFSR	0.0	0.0	0.0	0.0
Deferred Costs [before contributions]	453.0	2,025.0	-2,478.0	0.0
Deferred Cost Contributions	0.0	0.0	0.0	0.0
Intangible Assets	0.0	380.0	-380.0	0.0
Total	**47,315.9**	**30,817.7**	**-48,361.8**	**29,771.9**
Tab 5, Table 5.7				
Total Major Projects [before contributions]	34,564.1	34,790.0	0.0	69,354.1
Maintenance Capital [before contributions]				
Total Generation	216.7	485.0	0.0	701.7
Total Transmission	0.0	100.0	0.0	100.0
Total Distribution	0.0	250.0	0.0	250.0
Total General Plant & Equipment	0.0	400.0	0.0	400.0
Capital Contributions	-16,500.0	-4,500.0	0.0	-21,000.0
Deferred Costs [before contributions]	25,367.6	8,345.0	0.0	33,712.6
Deferred Cost Contributions	-288.5	0.0	0.0	-288.5
Intangible Assets	174.8	4,450.0	0.0	4,624.8
Total	**43,534.6**	**44,320.0**	**0.0**	**87,854.6**
Combined for 2023 Table 5.4 and Table 5.7				
Total Major Projects [before contributions]	80,882.0	56,690.0	-38,446.1	99,125.9
Maintenance Capital [before contributions]				
Total Generation	216.7	1,560.0	-1,075.0	701.7
Total Transmission	405.0	1,179.0	-1,484.0	100.0
Total Distribution	0.0	1,005.0	-755.0	250.0
Total General Plant & Equipment	140.0	2,872.0	-2,612.0	400.0
Capital Contributions	-16,500.0	-4,900.0	400.0	-21,000.0
Right of Use Assets	0.0	0.0	0.0	0.0
Total Overhaul	0.0	850.0	-850.0	0.0
Total Net RFID	0.0	681.7	-681.7	0.0
Total Net RFSR	0.0	0.0	0.0	0.0
Deferred Costs [before contributions]	25,820.6	10,370.0	-2,478.0	33,712.6
Deferred Cost Contributions	-288.5	0.0	0.0	-288.5
Intangible Assets	174.8	4,830.0	-380.0	4,624.8
Total	**90,850.5**	**75,137.7**	**-48,361.8**	**117,626.5**
PP&E	81,643.7	64,837.7	(45,903.8)	100,577.6
Transfer to RFID/RFSR	-	681.7	(681.7)	-
Net PP&E	81,643.7	64,156.0	(45,222.1)	100,577.6
Table 5.1 [net of Transfer to RFID/RFSR]	81,643.7	64,156.0	(45,222.1)	100,577.6
Variance	-	-	-	-
Capital Contributions	(16,500.0)	(4,900.0)	400.0	(21,000.0)
Table 5.1	(16,500.0)	(4,900.0)	400.0	(21,000.0)
Variance	-	-	-	-

REFERENCE: **Application, PDF pages 129-132**

ISSUE: **Major Projects > $1 Million – Rate Base Additions**

QUESTION:

a) Referring to the project Thermal Replacement (16.5 MW), please confirm that the 2024 Closing CWIP amount of $29.771 million as shown on PDF page 147, page 5-21, Table 5.5 reflects that the capitalization of the 5 MW diesel replacement at Faro in 2024 has occurred. If confirmed, please provide a table with a column illustrating, by major project cost component, the expenditures comprising the 2024 Closing CWIP amount of $29.771 million and a column illustrating the expenditures comprising the remaining work to be completed.

b) Referring to the response to part (a), please identify on PDF page 152, Page 5-26, Table 5-7, where the $29.771 million in 2024 Closing CWIP can be found.

c) For the Major Projects > $1 Million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in--service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

d) For the Major Projects > $1 Million that are forecast to be completed and in service in 2024, please provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

ANSWER:

(a)

Confirmed. The 2024 closing WIP balance in Table 5.5 of $29.771 million, subject to correction noted below, reflects the costs incurred to that point for the Dawson and Whitehorse portions of the Thermal Replacement Project, neither of which are impacting rate base during the test years, and reflects that the capitalization of the 5 MW diesel replacement at Faro in 2024 has occurred.

The following clarifications/corrections are noted:

- On review, YEC finds that the cost in WIP by end of 2024 in Table 5.5 of the Application for the Thermal Replacement project is not correct. It should be $39.329 million, not $29.771 million [the capital spending forecast for 2024 is not $13.0 million as shown in Table 5.5, but $22.558 million]. This correction does not impact the forecast revenue requirements for the 2023 and 2024 test years, i.e., all of the added capital spending in this correction goes to the corrected WIP at the end of 2024.

- It is also noted that the corrected WIP at the end of 2024 is not the forecast total cost for the Dawson and Whitehorse components of this project as it does not include remaining forecast costs to complete the Whitehorse diesel component in 2025. The total forecast cost for Whitehorse and Dawson diesel completion is $42.4 million as indicated on page 5.1A-4 of the Application:

  > The Thermal Replacement project is also proceeding with the following components at Whitehorse and Dawson at a forecast cost of approximately $42.4 million to provide further displacement of diesel rental requirements for winter 2025/26 (these project component costs are forecast to remain in WIP at the end of 2024 and therefore do not affect 2023/24 GRA revenue requirements).

- To clarify the components of the project identified in the Application as “Thermal Replacement (16.5 MW)”, it is noted that this project includes the following (see also note to “d” below):
  - 5 MW diesel replacement in Faro (in-service in 2024 and included in GRA test year rate base for 2024);
  - 5 MW diesel replacement in Whitehorse (forecast in-service in 2025); and
  - 6.5 MW diesel in Dawson (forecast in-service in 2024 but not included in GRA test year rate base for 2024) that includes:
    - one 3.25 MW unit replacing two end-of-life diesel engines at Dawson downtown plant with one new engine at the Callison substation.
    - 3.25 MW second diesel generator at the Callison substation to prevent prolonged outages during emergencies.

The following table shows major cost components for the $42.390 million portion for Whitehorse and Dawson components which are not impacting rate base during the 2023 and 2024 test years, including the corrected 2024 ending WIP balance of $39,329 million.

Thermal Replacement Forecast Costs: Dawson and Whitehorse Diesels

Major cost components	by end of 2024	2025 Forecast	Total
	$000	$000	$000
EPC Contractor - Dawson	$21,305	$0	$21,305
EPC Contractor - Whitehorse	$12,745	$1,450	$14,195
Previous Stagegate	$1,313	$0	$1,313
Station Service Supply (Faro and Dawson)	$314	$0	$314
YEC Internal Cost	$676	$150	$826
Owner's Engineer (BBA)	$407	$50	$457
Feasibility & Engineering	$113	$0	$113
Assessment and permitting	$202	$0	$202
Communication and Public Engagement	$125	$0	$125
First Nation Engagement	$70	$0	$70
Fuel (Onsite Commissioning)	$320	$300	$620
AFUDC	$392	$800	$1,192
Contingency	$1,347	$311	$1,658
Total	**$39,329**	**$3,061**	**$42,390**

(b)

Not applicable. Table 5-7 deals only with projects that are not included in test year rate base. The Thermal Replacement project does impact rate base and therefore is not included in Table 5.7.

(c)

Projects Closing in 2023	In-service? (Yes/No)	Expected in-service date	Explanation
Capital Projects – Major projects > $1 million – Rate Base Additions			
Whitehorse Stoplog Crane Replacement	No	Q3 2024	Project could not be completed in 2023 due to contractor delay. No change in scope or cost.
MH0 Road & Road Slope Stability	No	Q3 2024	Contractor did not complete hydroseed in 2023. No Change in scope. Cost increase due to quantity variance.
Transmission Line Replacement L178	Yes		
2023 Mayo-Faro Diesel Infrastructure	Yes		
P&C: S250 Callison Protection, Control and SCADA Upgrade	No	Q2 2024	Project delayed due to design flaw resulting in increased scope and cost required to address.
Wareham Spillway Concrete Repair	Yes		
Schwatka Lake Safety/Debris Boom	No	Q2 2024	Delay in materials. No change in scope or cost.

(d)

Projects Closing in 2024	Expected in-service date	Explanation
Capital Projects – Major projects > $1 million – Rate Base Additions		
Thermal Replacement (16.5 MW)	Q3 2024	Expected in-service of 5 MW at Faro (see Notes)
Whitehorse Interconnection	Q1 2024	
Transmission Line Replacement L178	Q4 2024	
Dawson Voltage Conversion	Q4 2024	
Whitehorse Spillway Stoplog Refurbishment	Q4 2024	
Lewes River Boat Lock Road Access Rebuild	Q4 2024	

Notes re: Thermal Replacement Project:
Expected Thermal Replacement in-service.in Q3 2024 referenced in the above table, and that is included in the Application 2024 test year rate base, is only for the 5 MW located at Faro (see explanation below and response to YUB-YEC-1-65(a) above).

The 10-Year Renewable Electricity Plan identified 12.5 MW of diesel replacement facilities at Whitehorse, Faro and Dawson planned for in-service during winter 2023/24. During implementation of this plan, YEC was also able to add 4 MW of additional diesel at Dawson City that will result in 6.5 MW of new diesel capacity in that community and 16.5 MW for what is identified as the Thermal Replacement Project (the initial planned 2.5 MW replacement unit at Dawson was replaced by a 3.25 MW unit based on equipment availability, and a second 3.25 MW unit was added as part of the project to support back-up power in that community based on growing demands at Dawson City). Based on information available today, the 6.5 MW being installed at Dawson is forecast to be in-service in Q4 2024, but is not in test year rate base due to inability reliably to cancel equivalent diesel rental capacity. The remaining 5 MW diesel replacement at Whitehorse is forecast to be in service in Q2 2025.

REFERENCE: **Application, PDF pages 132-135**

ISSUE: Projects $100,000 to $1 Million

QUESTION:

a) For all Projects $100,000 to $1 million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is an expected change in project scope or cost.

b) For all Projects $100,000 to $1 million that are forecast to be completed and in service in 2024, please provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is an expected change in project scope or cost.

c) Referring to the distribution project IPP Connections (page 5-8), please explain why contributions of $6.401 million exceed the project costs of $5.205 million.

ANSWER:

(a)

Please see table below.

Projects Closing in 2023	In-service? (Yes/No)
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions	
Generation	
MBH1/2 Seal Water Filtration	Yes
Subtotal	
Transmission	
L177 Re Route	Yes
NWTEL Make Ready Work	Yes
Subtotal	
Distribution	
Synchronous Condenser Overhaul	Yes
Dawson Distribution 3 Phase Loop	Yes
Subtotal	
General Plant	
New Mobile Office Unit - IT	Yes
Vehicle Purchases	Yes
Compact Digger Truck	Yes
Skid Steer	Yes
Mayo-McQuesten Radio to Fiber Migration	Yes
Waste Management Equipment	Yes
Subtotal	
Overhaul	
AH1 10 Year Overhaul	Yes
WG1 Overhaul	Yes
WG2 Overhaul	Yes
Subtotal	
Right of Use Assets	
Right of Use Asset 1 Lindeman Road	Yes
Subtotal	

(b)

Please see table below.

Projects Closing in 2024	Expected in-service date	Explanation
Capital Projects – Projects $100,000 to $1 million - Rate Base Additions		
Generation		
WH4 Air Admission Valve Automation	Q4 2024	
WG2 Cylinder Heads Swap	2025	Project postponed due to internal resource constraints
WG1 Radiator Replacement	N/A	Project deemed no longer necessary
Subtotal		
Transmission		
P&C: S170 Protection, Control and SCADA Upgrade	2025	Project postponed due to internal resource constraints
L177 Gang Switches	2025	Project postponed due to internal resource constraints
Transmission Line Test and Treat Program	Q4 2024	
Subtotal		
General Plant		
Major Crane Assessment/Refurbishment	2025	Project postponed due to internal resource constraints
Vehicle Purchases	Q4 2024	
HQ Datacenter Server Replacement	Q4 2024	
SCADA Operation Network Segregation	Q4 2024	
Subtotal		
Overhaul		
WG3 Overhaul	Q3 2024	
DD4 Overhaul	2025	Project postponed due to internal resource constraints
Subtotal		

(c)

IPP Connections are estimated in advance of the work being completed. All estimates are subject to a range of accuracy depending on the stage the project is at in the interconnection process. For example, preliminary engineering work advances based on a Class 4 estimate with a –30% to +50% range and detailed engineering advances based on a Class 2 estimate with a –5% to +20% range. The overall actual costs are within the anticipated estimated accuracy range even with estimating IPP project costs being more challenging based on the inflation of equipment, supply chain timeline uncertainty, and labour shortages. All completed IPP Connection projects will be added to rate base at a net cost of zero.

REFERENCE: **Application, PDF page 136**

ISSUE: Major Deferred Projects > $1 Million – Rate Base Additions

QUESTION:

a) For the Major Deferred Projects > $1 Million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

b) For the Major Deferred Projects > $1 Million that are forecast to be completed and in service in 2024, please provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

ANSWER:

(a)

Please see table below.

Projects Closing in 2023	Opening WIP	Capital Expenditures	Completed Projects	In-service? (Yes/No)
Deferred Costs – Major projects > $1 million – Rate Base Additions				
DSM Program 2022-2030	0.0	1,271.6	-1,271.6	Yes
DSM Program Development Contributions	0.0	-21.6	21.6	Yes
Southern Lakes Storage	8,784.2	0.0	-8,784.2	Yes
Aishihik 5-Year License Renewal	575.4	0.0	-575.4	Yes
Subtotal	**9,359.5**	**1,250.0**	**-10,609.5**	

(b)

Projects Closing in 2024	Opening WIP	Capital Expenditures	Completed Projects	Expected in-service date
Deferred Costs – Major projects > $1 million – Rate Base Additions				
DSM Program 2022-2030	0.0	1,160.0	-1,160.0	Q4 2024
Subtotal	**0.0**	**1,160.0**	**-1,160.0**	

REFERENCE: **Application, PDF pages 137-138**

ISSUE: Deferred Projects between $100,000 and $1 Million – Rate Base Additions

QUESTION:

a) For the Deferred Projects $100,000 to $1 million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

b) For the Deferred Projects $100,000 to $1 million that are forecast to be completed and in service in 2024, please provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

ANSWER:

(a)

Please see table below.

Projects Closing in 2023	In-service? (Yes/No)	Expected in-service date	Explanation
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions			
Atlin EPA Section 18 Proceeding (Hearing Reserve Acct)	Yes		
Public Safety Plans	Yes		
System Wide Stability Study	No	Q4 2024	Project not completed due to internal resource constraints. No change in scope or cost.
System Wide Arc Flash Study	No	Q4 2024	Project not completed due to internal resource constraints. No change in scope or cost.
Mayo Civil Infrastructure Refurbishment Planning	Yes		
Digital Strategy and Policy Development	No	Q4 2024	Project delayed due to scope modifications.
Privacy Management Program	No	2025	Project not completed due to internal resource constraints. No change in scope or cost.
Vegetation Management Plan Update	No	Q2 2024	Project could not be completed in 2023 due to Contractor Delay - No change in scope or cost
IPP Standing Offer Program Implementation	Yes		

1

(b)

Please see table below.

Projects Closing in 2024	Expected in-service date	Explanation
Deferred Costs – Projects $100,000 to $1 million - Rate Base Additions		
WRGS Thermal Assessment & Permitting	Q4 2024	
Cyber Security Framework	Q4 2024	
Transmission Line Detailed Inspection Program	Q4 2024	
Gates/TIV's Certification Assessment System Wide	Q4 2024	
Digital Reporting Review	2025	Project postponed due to internal resource constraint
Records Policy Planning and Program Development	2025	Project postponed due to internal resource constraint
Breaker Condition Assessment	Q4 2024	

REFERENCE: **Application, PDF pages 138-139**

ISSUE: Intangible Assets, Major Projects > $1 Million – Rate Base Additions

QUESTION:

a) For the Major Projects > $1 million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

ANSWER:

(a)

Please see the table below.

Projects Closing in 2023	**In-service? (Yes/No)**
Intangible Assets – Major projects > $1 million - Rate Base Additions	
PAMMS Asset Management Framework	Yes

REFERENCE: **Application, PDF page 139, page 5-13**

ISSUE: Intangible Projects between $100,000 and $1 Million – Rate Base Additions

QUESTION:

a) For the Intangible Projects between $100,000 to $1 million that are forecast to be completed and in service in 2023, please confirm that the assets are currently in service or provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

b) For the Intangible Projects between $100,000 to $1 million that are forecast to be completed and in service in 2024, please provide an update on the expected in-service date as of the date of filing the response to this IR. For any change to the expected in-service year, please provide reasons and whether there is a change in project scope or cost.

ANSWER:

(a)

Please see the table below.

Projects Closing in 2023	In-service? (Yes/No)	Expected in-service date	Explanation
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions			
Network Software Traffic Shaping	No	Q4 2024	Project not completed due to internal resource constraints. No change in scope or cost.
CIS Replacement	Yes		

(b)

Please see the table below.

Projects Closing in 2024	Expected in-service date	Explanation
Intangible Assets – Projects $100,000 to $1 million - Rate Base Additions		
P&C Central Event Data Collection System	2026	Project postponed due to internal resource constraint.
SharePoint Upgrades	Q4 2024	

REFERENCE: **Application, PDF pages 155-156**

ISSUE: Changes for projects reviewed and approved in 2021 GRA

PREAMBLE: YEC explains that there has been a "total adjustment of $2.728 million added to the rate base previously approved in 2021 GRA"; however, the numbers provided for the Mayo-McQuesten Transmission Line Upgrade project (a reduction of $0.507 million to rate base) and Replace P125 WH2 Head Gate project (an addition to rate base of $2.221 million) do not total $2.728 million.

QUESTION:

a) Please confirm whether there is a mathematical error as noted in the preamble.

b) If part (a) is confirmed, please verify that the rate base additions have been recorded correctly.

ANSWER:

(a) and (b)

Yes, there is a mathematical error on page 5.1A-2 in Appendix 5.1A of Tab 5 where it is noted that "total adjustment of $2.728 million added to the rate base previously approved in 2021 GRA". The numbers provided in the two sub-bullets are correct (reduction of $0.507 million to rate base for Mayo-McQuesten Transmission Line Upgrade, and increase of $2,221 million to rate base for P125 WH2 Head Gate replacement project).

The correct wording for the referenced section on page 5.1A-2 is: "total adjustment of $1.714 million added to the rate base previously approved in 2021 GRA:"

REFERENCE: **Application, PDF pages 170-171**

ISSUE: Capital project: Transmission Line Replacement L178

QUOTE:

Table 5.1A-4.1: Summary of Scope of Transmission Line Refurbishment Work (L178) – Number of Structures

Work Description	Assessment 2018	Completed Through 2022	Planned 2023-2027
Full structure replacement	144	52	92
Cross arm replacement	102	38	64
Insulator replacement	549	162	387
Total structures replacement	**795**	**252**	**543**
No maintenance required	39	-	-
Total structures	**834**	**252**	**543**

…

This total project cost has increased substantially from the 2021 GRA estimate of $8.3 million for a number of reasons.

- L178 is the only line in the WAF system that required significant rock blasting in order to replace certain structures.
- Further, the terrain in the area is much less accessible, requiring specialized equipment and increased installation time for each structure. Inflationary pressures have driven both contractor rates and material costs higher than anticipated over the last few years.
- Additionally, the cost to permit and build access roads to the structure locations has been included in the cost of this project (this was planned to be done separately as of the last GRA, similar to the other transmission lines).

PREAMBLE: On PDF page 171, Table 5.1A-4.1, Summary of Scope of Transmission Line Refurbishment Work (L178), indicates that there are 543 structures forecast to be replaced between the years 2023 to 2027, with the work to be completed in 2023-2024 costing approximately $6.00 million. The table currently consists of three columns.

QUESTION:

a) Please replace the planned 2023-2027 work column (the third column) currently in Table 5.1A-4.1, Summary of Scope of Transmission Line Refurbishment Work (L178), with four columns to provide information respecting: (i) Actual 2023 to Date, (ii) Remaining Planned 2023, (iii) Planned 2024, and (iv) Planned 2025-2027. At the bottom of each of the (now six)[1] columns, please include a row detailing "the cost to permit and build access roads to the structure locations," a row of the remaining actual or forecast costs, and a row totalling all actual or forecast costs.

b) In table form, please identify (by area) where the 2022 actual to date and forecast 2023 and 2024 replacements will occur and the number of poles to be replaced in each of those areas.

c) Given that this project is replacing or refurbishing existing transmission line structures, please explain why the conditions noted by YEC in the above quote were not factored into the original project budget.

d) Please fully explain whether the transmission line refurbishment work on L178 is being done by YEC or YEC contractors.

ANSWER:

(a)

Please see Revised Table 5.1A-4.1 below (Number of Structures by year)

Work Description	Assessment 2018	Completed Through 2022	Actual 2023 to date	2023 Remaining	Planned 2024	Planned 2025-2027	Planned 2023-2027
Full structure replacement	144	52	0	0	40	52	92
Cross arm replacement	102	38	1	0	0	63	64
Insulator replacement	549	162	94	0	0	293	387
Total structures replacement	**795**	**252**	**95**	**0**	**40**	**408**	**543**
No maintenance required	39	-	-	-	-	-	-
Total structures	**834**	**252**	**95**	**0**	**80**	**408**	**543**
Cost to permit and build access roads		-	4,418.75	335,128.30	400,000.00	400,000.00	1,139,547.05
Installation and all other costs		5,083,470.95	332,428.76	132,442.94	4,600,000.00	8,150,000.00	13,214,871.70
Total Costs		5,083,470.95	336,847.51	467,571.24	5,000,000.00	8,550,000.00	14,354,418.75

[1] The six columns are: Assessment 2018, Completed through 2022, Actual 2023 to Date, Remaining Planned 2023, Planned 2024, and Planned 2025-2027.

(b)

The Transmission Line Replacement L178 project is for the approximate 180 kilometres between Carmacks and the Faro Mine. In 2022, the project focused on structures with the most difficult terrain and foundations type (rock). In 2023, most of the work was allocated to component replacements. The rest of the costs were to complete a heritage assessment of the entire right-of-way's and a survey to gather the information required to permit and upgrade exiting access and construct new permanent access.

The current plan for 2024 is to focus on

1. Access – Permitting, constructing, and upgrading access.
2. Structure replacements
    a. Actual installations;
    b. Civil works required to travel ROW.
3. River crossing structure near Faro.

The current working strategy is to go to market and procure a contractor that can provide the best value and execute the three above activities. The contract would be multi-year. Component replacement is not currently being considered for 2024 but will take place in future years.

(c)

The original estimate incorrectly assumed that conditions and costs were similar to line L171 that was previously refurbished.

(d)

The work is being done primarily by contractors with YEC powerline technicians supporting the project as required (typically during isolation of the transmission line).

REFERENCE: **Application, PDF page 173**

ISSUE: Capital project: S250 Callison Protection, Control and SCADA Upgrade

QUOTE: Due to the extensive work required, Dawson City will need to be islanded on diesel for as long as one month, with the Callison Substation in a full outage for several weeks.

QUESTION:

a) Please explain if either of the events (islanded and full outage) identified in the quote have occurred as of the date of filing the response to this IR.

ANSWER:

(a)

The Callison substation was taken out of service (resulting in Dawson City being islanded and supplied by diesel generation) from July 4 to August 4 and again from September 26 to October 3.

REFERENCE: **Application, PDF page 177**

ISSUE: Capital project: Wareham Spillway Concrete Repair

PREAMBLE: In its business case, YEC describes frequent and ongoing concrete repairs for the Wareham spillway at the Mayo Generating Station.

QUESTION:

a) Please explain why the repairs identified in the business case should not be considered a repair and maintenance expense rather than a capital addition given their frequency and ongoing nature.

b) In capitalizing the frequent and ongoing concrete repairs for the Wareham spillway at the Mayo Generating Station, can YEC confirm that the expenditures have extended the useful service life of the Wareham Spillway?

ANSWER:

(a)

In YEC's opinion, one could justify the recording of the Wareham Spillway Concrete Repair as capital or as a maintenance expense. YEC's final decision to capitalize was based on the original engineering assessments that the fixes would last at least five years. This accounting treatment is also beneficial to ratepayers as the entire expense is not all recorded in one year.

During 2023, YEC retained Stantec to carry out a site visit to observe the condition of the spillway chute and the mitigations completed in 2021 and 2022. At the completion of the study, Stantec provided drawings for the work required to enable the spillway to be used for the next several years. The study showed some of the previous fixes were working well, others needed reinforcement, and other sections of the spillway not previously fixed are requiring work. Permanent replacement of the spillway is estimated to be completed between 2027 and 2030.

(b)

As part of the 2021 year-end accounting procedures and audit, YEC wrote off all previous Wareham Spillway costs as there was considered no useful service life left at that time. Therefore, all previous Wareham Spillway costs have been removed from rate base and are not being recovered from ratepayers. As a result, the current expenditures on the Wareham Spillway were assumed to extend the life of the Wareham Spillway from zero to five years. This is consistent with the expectation that the permanent fix will be completed between 2027 and 2030.

REFERENCE: **Application, Section 5.1A-9, PDF pages 178-179**

ISSUE: Stoplog Crane Replacement

QUOTE: The EPC contract was publicly tendered. Project costs are summarized in the table below.

QUESTION:

a) How many vendors did YEC solicit for the tendering process?

b) How many quotes were received as a result of the public tender process?

c) What was price range of the quotes received?

d) Did YEC or an outside party administer the public tender process? Please explain.

e) What is the current status of the project?

f) What are the costs to date for this project? Please provide a breakdown similar to the table provided on PDF page 179.

ANSWER:

(a)

YEC posted the tender on Merx, a Canadian electronic tendering service used by many public sector organizations, to reach as many vendors as possible.

(b) and (c)

YEC received one proposal for a portion of the multi-stage project. The proposal price for the Crane and Follower Beam Design, Supply, Installation, and Commissioning portion of the Project was about $2.7 million, excluding GST. It is important to note that this cost does not include YEC's internal costs, owner's engineering, AFUDC and contingency. The forecast cost of $4.3 million in the Application is total of these costs.

(d)

The public tender process was administered by YEC.

(e)

Fabrication of the new crane components is currently being completed.

(f)

The following table shows the cost to date for the Project.

Item	**Cost**
YEC Costs / PM / Inspections	$113,672
Owner's Engineer	187,415
Crane and Follower Beam Design, Supply, Installation, and Commissioning	2,007,149
AFUDC	22,564
Total	$2,330,800

REFERENCE: **Application, Section 5.1B-4, PDF page 216**

ISSUE: Vehicle purchases

PREAMBLE: The Board seeks further information.

QUESTION:

a) Please provide a single table showing each vehicle purchased or forecast to be purchased broken down by year for 2021 to 2024, with additional columns showing the actual or forecast capital costs and any applicable AFUDC, showing AFUDC separately from the capital costs.

ANSWER:

(a)

Unit	Vehicle Description	2022	2023	2024
146	Mechanical - 3/4 Tonne replacing unit # 113	68,866.15		
147	Mechanical - 2 Tonne with service body replacing unit # 95	136,975.30		
148	VP Operations 1/2 tonne truck replacing unit # 91	49,638.98		
149	Director Operations 1/2 tonne truck replacing unit # 99	49,797.84		
150	Engineering 3/4 tonne with slide in canopy replacing unit # 104	87,477.39		
151	Mechanical - 3/4 tonne replacing unit # 115	67,075.14		
154	Mechanical 1/2 tonne truck replacing unit # 89		63,368.65	
155	SCC - 1/2 tonne replacing unit # 100		62,709.81	
156	T&D 1 Tonne truck with Service Body replacing unit # 116		151,893.67	
157	Mechanical - 2 Tonne with service body replacing unit # 94		186,218.00	
158	Electrician 1 Tonne with Service Body replacing unit # 105		145,155.38	
153	Mechanical - 1 tonne extended cab with storage boxes replacing unit # 103			113,567.12
159	T&D 1 Tonne truck with Service Body replacing unit # 110			149,009.33
160	Electrician 1 Tonne with Service Body replacing unit # 111			149,009.33
161	Mechanical 3/4 tonne truck replacing unit # 109			91,965.69
162	Mechanical 1/2 tonne truck replacing unit # 98			87,231.47
AFUDC		3,354.92	1,996.20	2,000.00
Total		**463,185.70**	**611,341.71**	**592,782.94**

Note: Due to supply chain challenges, no vehicles were purchased in 2021. The forecast for 2024 is updated, and shows approximately $25,000 more than the Application.

REFERENCE: **Application, PDF page 183**

ISSUE: Capital project: Lewes River Boat Lock Road Access Rebuild

QUOTE: There are two options for restoring access to the east side of Lewes:

1. Restore the original access; or
2. Upgrade the temporary access and have a disposition so that YEC has permanent access.

Leaving the damaged road in its current condition is not an option as proper access is required for rebuilding the damaged boat lock and long-term inspection work.

A request for proposal for a design engineer is being completed in 2023, and design should be ready by year-end.

As part of this contract, the two options will be assessed and determined which one will be the most cost effective to both restore/upgrade and maintain.

The construction will be completed during the 2024 construction season in order have the road ready for 2025 repair of the boat lock.

PREAMBLE: YEC has forecast a rate base addition of $1.2 million in 2024 for this project; however, it is not clear what the costs are comprised of or if any additional costs are forecast to be incurred in 2025.

QUESTION:

a) Please identify the specific costs YEC is proposing to capitalize in 2024 given that it appears the repair is intended to be completed in 2025.

b) If the response to part (a) is that the $1.2 million is costs for the “design”, please explain why these costs should be capitalized in advance of any other work to be completed subsequent to the year 2024.lease explain why costs associated with the test and treat program are not considered a repair and maintenance expense.

ANSWER:

(a)

YEC is proposing to capitalize the costs to repair the boat lock *access road* in 2024 as the work is expected to be completed. The work intended to be completed in 2025 is the repair of the boat lock itself (a separate project), which will require access via the road to allow construction activities.

(b)

The $1.2 million is the full cost of the project including design and construction.

REFERENCE: **Application, PDF page 209**

ISSUE: Capital project: Transmission Line Test and Treat Program

QUOTE: The program treats ant colonies with insecticide, treats poles with fumigant to slow decay, treats external damage with preservative, and performs internal inspection of the pole to measures shell thickness to assess the pole condition.

QUESTION:

a) Please explain why costs associated with the test and treat program are not considered a repair and maintenance expense.

ANSWER:

(a)

In YEC's opinion, one could justify the recording of the Transmission Line Test and Treat Program as capital or as a maintenance expense. YEC's final decision to capitalize was based on the assessments that the program does not need to be repeated at the same location for several years. This accounting treatment is also beneficial to ratepayers as the entire expense is not all recorded in one year.

REFERENCE: **Application, Section 5.1B-4, PDF page 216**

ISSUE: New Mobile Office Unit - IT

PREAMBLE: The Board is seeking further information.

QUESTION:

a) Existing IT trailer:
   i. When was it acquired?
   ii. What is its square footage?
   iii. What were the initial costs, including all site preparation costs?
   iv. Provide the annual maintenance costs for this trailer by year since acquisition.
   v. How was the trailer deemed to be at the end of its life and by whom?
   vi. What are the ongoing indoor air quality issues, and what is the source of those issues?

b) Proposed IT trailer:
   i. What is the current status of the project?
   ii. What are the costs to date?
   iii. What is its square footage?
   iv. Please provide a breakdown of the forecast costs.
   v. Has this project been publicly tendered?
   vi. If publicly tendered, who administered the tendering process?
   vii. If publicly tendered, how many vendors responded and what was the price range?
   viii. If not publicly tendered, please explain how the vendor was selected.
   ix. If not publicly tendered, how can YEC ensure competitive pricing?
   x. What is the expected life of the replacement trailer?

ANSWER:

(a)

i) The trailer was acquired in 1997 (built in 1991).

ii) 990ft^2.

iii) This information is not available.

iv) Annual maintenance costs ranged from $6,000-$12,000 per year depending on end of life equipment and indoor air quality issues.

v) The trailer was deemed to be at end of life by YEC staff based on the cost of necessary major repairs.

vi) The source of the indoor air quality issues was initially identified as high moisture levels in the crawl space that was inadequately vented. After the old trailer was removed, it was determined that it was situated on a contaminated site which likely played a role in the air quality problem.

(b)

i) The trailer is on site and occupied by staff, however there are outstanding deficiencies to be addressed prior to project completion.

ii) $591,423.

iii) 2,000 ft^2.

iv)

Cost Category	Amount
Old Trailer decommission / ground preparation	$40,000.00
Office Trailer	$382,437.36
Shipping	$69,375.00
Installation	$135,000.00
Security + Fire Panel hook-up	$30,000.00
Total	$656,812.36

v) Yes, the work was tendered via MERX.

vi) YEC staff.

vii) Four vendors responded with quotes ranging from $522,353.36 to $893,193.00.

viii) N/A.

ix) N/A.

x) 40-60 years.

REFERENCE: **Application, PDF pages 138-139, 389-474; Appendix A to Board Order 2022-03, PDF page 76, pars. 332 and 333**

ISSUE: Intangible assets – EAM & PAMMS

QUOTE: Application, PDF page 390:

In GRA 2021, the YUB disallowed YEC's costs on the EAM based on concerns about the adequacy of the evidence presented by YEC in that application to support it (Board Order 2022-03, Appendix A, paras 332-333). Given the importance and the essential need for the EAM and related AM activities YEC has taken the necessary steps in its present 2023 GRA application to address the concerns identified by the YUB so that previously disallowed expenditures can now be properly included in rate base.

Appendix A to Board Order 2022-03, PDF page 76:

332. The Board accepts that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000. However, the Board is concerned with the EAM project as proposed in this Application. YEC justified the tangible benefits related to productivity gains by referencing the results of a case study by Booz & Company and the anticipated savings from better inventory management by providing a BC Hydro document; it cited non-YEC specific case studies to determine the reductions in long-term asset costs. None of this evidence was prepared based on project-specific information, which in the Board's view limits the evidence's persuasiveness. As an example, YEC mentioned that organizations with EAM have reported reductions in long-term asset costs of up to five percent but could not provide any organizations that showed reductions in long-term asset costs. Thus, the Board finds it was not reasonable for YEC to proceed with the project given that the benefits lacked project-specific evidence.

333. Additionally, YEC stated that it explored other software alternatives but did not provide any details on these alternatives and why they were ruled out in favour of the EAM project. Regarding the chosen vendor for the software solution, YEC stated it scored higher on

technical merits compared to the lowest bidder. However, YEC did not provide any details on these technical merits. Accordingly, the Board does not have sufficient evidence to assure itself that the EAM project was a reasonable alternative for YEC to pursue with regard to asset management. For these reasons, the Board finds the costs associated with this project are not reasonable and denies inclusion of the costs for this project in the 2021 rate base. The Board directs YEC to reflect the denial in the compliance filing to this Board Order. (Footnotes omitted.)

PREAMBLE: In Board Order 2022-03, Appendix A, pars. 332 and 333, the Board denied certain of YEC's capital costs for the two intangible asset projects. The Board seeks to understand on what basis the previous disallowances may be altered by the information now being provided by YEC in the current Application.

QUESTION:

a) Please explain on what regulatory and/or legal basis YEC is asking the Board to examine the disallowed costs for the EAM and PAMMS intangible assets which YEC has now added to its rate base.

b) Please provide the date on which the EAM and PAMMS projects resulted in used and useful utility assets.

c) Please provide the date on which the EAM and PAMMS projects were recorded as capital assets in YEC's accounting records.

d) Please confirm — notwithstanding that the Application, PDF page 142, Table 5.2, Work in Progress Continuity Schedule – 2021, shows capital additions in the year 2021 that appear to include the disallowed portions of EAM and PAMMS — that YEC's 2023-24 revenue requirement has not sought any recovery of revenue associated with the disallowed portion of the project costs for the years 2021 or 2022.

e) Should the requests for costs for these projects from 2021 be considered as retroactive ratemaking? If not, please explain.

ANSWER:

(a)

The Board retains authority and responsibility under the *Public Utilities Act* (the "Act") in each GRA Application to review utility capital costs incurred to date, or forecast to occur during the current test years, for assets that are forecast to be used and useful during the current GRA test years. The Board's authority and responsibility to carry out this review is to determine if these costs are prudent and reasonably incurred and therefore to be included in the forecast revenue requirement for the current test years.

In particular, it is the Board's obligation under section 32(1) and (3) of the Act in each GRA Application to determine a rate base for the property of the utility that is used or required to be used to provide service to the public, giving 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.

The fact the Board may have concluded in a previous GRA Application that there was insufficient evidence in that proceeding to support including the costs of certain assets in YEC's rate base for a previous test year does not displace the Board's statutory obligation to include costs in YEC's rate base for the current test years that are supported by sufficient evidence in the current proceeding.

With respect to the EAM and PAMMS projects, in the 2021 GRA YEC only sought Board approval for the inclusion of EAM capital costs in rate base, and the Board only reviewed and disallowed costs for the EAM in Board Order 2022-03. Since the PAMMS project was not forecast to be completed until 2023, YEC did not seek to include capital costs for the PAMMS project in rate base in the 2021 GRA. Accordingly, the Board did not review or make any decision about PAMMS capital costs, and this IR has no relevance to the PAMMS capital costs that YEC is asking the Board to approve for the first time in the current Application.

The relationship between the interdependent but distinct EAM and PAMMS projects is outlined in more detail in Appendix 5.3A of the GRA Application.

As reviewed in the above quotes in this IR from Appendix A to Board Order 2022-03, the Board disallowed-denied inclusion of all EAM capital costs in rate base for the 2021 GRA

based on concerns about the adequacy of the evidence presented by YEC in the 2021 GRA (i.e., based on a lack of project-specific evidence of the EAM's expected benefits, or the technical merits of the selected software solution). However, the Board specifically acknowledged in its decision that alignment of asset management practices with recognized standards (i.e., ISO 55000) is appropriate.

YEC did provide evidence during the 2021 GRA proceeding from recognized industry experts that its previous Asset Management practices did not align with current standards, and those experts recommended the approach selected by YEC to select a replacement system. In that regard, it is YEC's position that the Board's wholesale denial of the EAM project costs in the 2021 GRA did not reflect the improvements to YEC's Asset Management practices that were achieved through implementation of the EAM. To assist the Board in the current proceeding, YEC commissioned additional review of the selection process to provide clear evidence of the superiority of the selection, specifically addressing the technical merits questions raised by the Board (see Section 5.3A-2 of Appendix 5.3A of the Application for a summary of these findings; the consultant's report is included in Attachment 5.3A-1).

Given the importance and the essential need for the EAM and related Asset Management activities during the 2023-2024 test years and beyond, YEC has provided additional information and clarifications on the relevant costs for the EAM intangible asset in order to address the information deficiency issues and concerns raised by the Board in its earlier Order related to the prior 2021 YEC GRA.

(b)

EAM was considered used and useful on March 30, 2021. PAMMS is forecast to be used and useful December 31, 2023.

(c)

EAM was recorded as a capital asset on March 30, 2021. PAMMS is forecast to be added as a capital asset December 31, 2023.

(d)

Not confirmed.

With regard to EAM, as disclosed on Page 5-13 of the Application, YEC is seeking recovery of rate base additions in 2021 relating to EAM total in service costs of $4.550 million, of which $0.276 million was spent in 2018, $0.534 million in 2019, $2.972 million in 2020 and $0.768 million in 2021. As addressed in (e) below, the current 2023-24 GRA Application YEC is not requesting recovery of EAM depreciation or return for the period from in-service (2021) to December 31, 2022.

With regard to PAMMS, there were no disallowed project costs in Board Order 2022-03 for the years 2021 or 2022 relating to PAMMS. YEC did not bring this project forward for inclusion in 2021 rate base in its 2021 GRA, and therefore there was no prudency assessment of PAMMS costs by the Board as part of any prior Application; the project is not scheduled to be completed and in-service until the end of 2023.

(e)

No.

With respect to the EAM project, in the current 2023-24 GRA Application YEC is not requesting recovery of depreciation or return for the period from in-service (2021) to December 31, 2022. The current Application only seeks recovery on a prospective basis (i.e. commencing January 1, 2023, at the start of the test years applicable to this Application) based on the evidence and business case provided to the Board in the current proceeding. This is consistent with the Board's statutory obligations under section 32 of the Act, and it cannot be considered to constitute retroactive rate making when YEC is not requesting any retroactive change to its revenue requirements or rates for 2021 or 2022 or for any other earlier time period that would constitute a request for retroactive ratemaking that is not provided for under the Act.

Further, PAMMS capital costs are being reviewed by the Board for the first time in the current Application – and the PAMMS assets only come into service in 2023. Accordingly, there is no basis for requests for costs for PAMMS to be considered retroactive rate making relating to years prior to 2023.

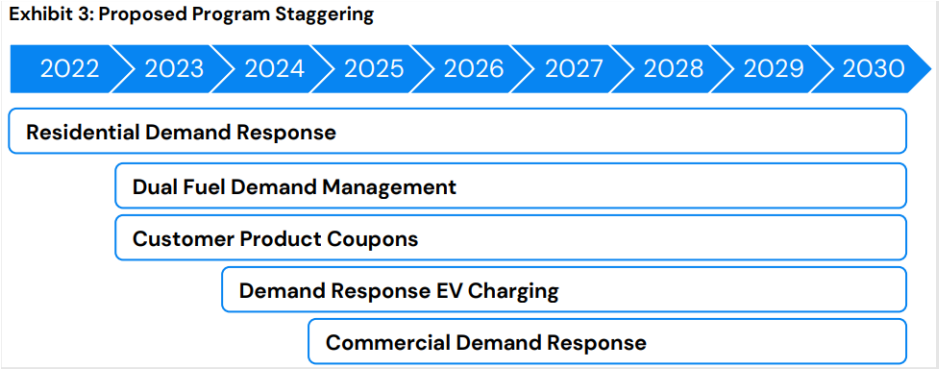
REFERENCE: **Application, PDF pages 236 and 277**

ISSUE: Demand Side Management (DSM) programs

QUOTE: Application, PDF page 236:

SECTION 5.2A-2: DEMAND SIDE MANAGEMENT (DSM) PROGRAM DEVELOPMENT AND DSM PROGRAM 2022-2030 (ADDITIONS TO RATE BASE [NET OF CONTRIBUTIONS] OF $0.010 MILLION IN 2021, $0.353 MILLION IN 2022, $1.250 MILLION IN 2023, AND $1.160 MILLION IN 2024)

PDF page 277:



PREAMBLE: It is not clear which programs comprise the total forecast costs for each test years' costs on an actual or forecast basis.

QUESTION:

a) Using the years and headings provided on PDF page 277 as quoted above and adding the year 2021, please prepare a table by year and DSM program that shows the capital expenditures forecast or actually incurred over those years for each proposed program. Please include a line for each DSM program providing any anticipated contributions from any entity.

ANSWER:

(a)

As shown in the table below, all costs to date have been attributed to the Residential Demand Response program. No budgets have been assigned to future programs to date. Program budgets for years 2025 and beyond have not been developed yet.

Program		2021	2022	2023	2024
Residential Demand Response	Expenses	$0.246M.	$0.246M	$1.272M	$1.160M
	Contributions	$0.250M	$0.038M	$0.0.22M	$0
	Net	-$0.004M	$0.208M	$1.25M	$1.160M
Dual Fuel Demand Management	Expenses	$0	$0	$0	$0
	Contributions	$0	$0	$0	$0
	Net	$0	$0	$0	$0
Customer Products Coupons	Expenses	$0	$0	$0	$0
	Contributions	$0	$0	$0	$0
	Net	$0	$0	$0	$0
Demand Response EV Charging	Expenses	$0	$0	$0	$0
	Contributions	$0	$0	$0	$0
	Net	$0	$0	$0	$0
Commercial Demand Response	Expenses	$0	$0	$0	$0
	Contributions	$0	$0	$0	$0
	Net	$0	$0	$0	$0

REFERENCE: **Application, PDF pages 61-62 and 291-293, Demand Side Management [DSM] Program designed for YEC**

ISSUE: DSM program - Dual Fuel Demand Management

QUOTE: Application, PDF page 291:

3.3.1 Program Description

With growing emphasis on electrification of home heating systems to reach Yukon and federal decarbonization targets, residents are being encouraged to upgrade their home heating systems with cold-climate heat pumps. The Energy Branch is offering rebates of 40% of eligible heat pump costs up to a maximum of $8,000 and has a target to replace 1,300 residential fossil fuel heating systems with “smart electric heating systems” by 2030. While heat pumps are a highly efficient means to heat and cool homes, when the outside temperature dips below its operating threshold the heat pump relies on an auxiliary heating system – typically in-duct electric coils. This would create significant additional demand during the peak period.

ICF recommends a dual fuel program modeled after the long-standing program offered by Hydro Quebec, called Rate DT. Participants receive a direct-installed dual fuel demand management switch to automatically switch from the heat pump to the fuel-burning forced-air system, when the outdoor air temperature drops below a threshold. Instead of a modified rate (as provided by Hydro Quebec in Rate DT), ICF recommends offering an on-bill performance incentive to participants for reducing their electricity consumption during peak periods. Initial sign-on incentives should also cover the cost of any upgrades required to the fossil fuel heating system (e.g. new heating oil tank) to ensure that the system is safe to continue operating.

YEC will need to collaborate with the Energy Branch, such that participants in the Good Energy Heating System Rebate program are advised to keep their fossil fuel heating system and coordinate their heat pump installation with their enrollment in the Dual Fuel Demand Management program.

[8] Government of Yukon, *Our Clean Future*, 2020 https://yukon.ca/sites/yukon.ca/files/env/env-our-cleanfuture.pdf
[9] Hydro Quebec, Rate DT – Dual Energy https://www.hydroquebec.com/residential/customerspace/rates/rate-dt.html

PREAMBLE: The Board wants to understand the relationship between YEC's proposal and the Energy Branch requirements for a rebate for heat pump installation.

QUESTION:

a) Please clarify if the Yukon Government consulted with YEC in relation to either the Government of Yukon's Our Clean Future document or "electrification and a transition to a net zero carbon economy policy."

b) Please explain how YEC's DSM program promoting the electrification of homes through the installation of cold-climate heat pumps while advising participant customers to keep their fossil fuel heating system and coordinate their heat pump installation with their enrollment in the Dual Fuel Demand Management program will meet the Energy Branch's target of replacing 1,300 residential fossil fuel heating systems with "smart electric heating systems."

c) Please explain how participant customers will be able to qualify for the Energy Branch's rebates if they are not able to or have not replaced a fossil fuel heating system with a non-fossil fuel heating system because they will have been "advised to keep their fossil fuel heating system and coordinate their heat pump installation with their enrollment in the Dual Fuel Demand Management program." As part of the response, please provide a quote of the specific Energy Branch language confirming that participating customers will qualify for a rebate under the conditions proposed by YEC's dual fuel management system.

d) Please discuss how the elasticity of the price of electricity in relation to YEC's proposed DSM programs would impact sales.

e) Please provide an estimate of the reduction of electrical energy consumption by the various classes of customers facing each of the 10-percent and 20-percent rate increase. Please include all applicable references in support of the estimates.

ANSWER:

(a)

In 2019, Yukon Government met with YEC staff and Board of Directors to discuss the government's plans to develop a Yukon strategy for climate change, energy and a green economy, now commonly referred to as Yukon government's Our Clean Future document.

Yukon government's strategy had four goals:

1. Reduce Yukon's greenhouse gas emissions.
2. Ensure Yukoners have access to reliable, affordable and renewable energy.
3. Adapt to the impacts of climate change.
4. Build a green economy.

As part of the strategy, three key targets were also identified by Yukon government that would directly affect the Yukon's electricity system.

1. By 2030, greenhouse gas emissions in the territory will be 30 per cent lower than 2010 levels. At the time, the Yukon government noted that the road transportation and heating sectors were the two largest contributors of greenhouse gas emissions in the territory accounting for a combined 75% of all greenhouse gas emissions in the Yukon in 2017.
2. By 2030, an average of 93 per cent of electricity used on the main electricity grid will come from renewable resources.
3. By 2030, 30 per cent less diesel will be used for electricity generation in the Yukon's off-grid communities.

As part of the consultation process, Yukon Energy provided feedback that electrifying the Yukon's heating and transportation sectors would increase demands for electricity. Reducing emissions in these sectors, while also maintaining Yukon Energy's ability to generate an average of 93% renewable electricity on the Yukon grid, would require:

- More sources of renewable energy and capacity to be developed.

- Government funding to offset the cost of new projects and programs to keep electricity rates affordable.
- The development of a First Nations Investment Framework that would outline opportunities for First Nations investment in future energy projects.
- The adoption of strict building codes related to the energy efficiency of new buildings.
- Expansion of energy efficiency and demand-side management programs including certainty that costs for these programs could be recovered through rates.
- Adoption of additional modes of transportation. For example, the use of natural gas for heavy duty transportation trucks and public transit, and car sharing/bicycle commuting.

On September 14, 2020, Yukon government's Our Clean Future strategy was publicly released.

On November 16, 2022, the Yukon's Clean Energy Act was assented. In it, the reduction target for total greenhouse gas emissions in the Yukon, not including mining sector emissions, for 2030 and subsequent years was increased from 30% to 45%, from the total greenhouse gas emissions in the Yukon in 2010.

In May 2023, YEC provided feedback to Yukon government about how changes to the emissions reduction target to 45%, while maintaining an average of 93% renewable generation on the main Yukon grid, would impact Yukon's electricity system. The feedback was shared as part of ongoing discussions between YEC and Yukon Government about the implementation of the Our Clean Future Strategy, including possible revisions to actions in the strategy based on updated information (i.e., new emission reduction targets).

In its comments, YEC noted that increases in emission reduction targets increases the urgency of investments in all aspects of the Yukon's electricity system including power generation, stability and storage, transmission and distribution, and end-use electrification. YEC also noted that incentives for end-use electrification and intermittent renewables need to be balanced with investments in new sources of dependable capacity, short and long-term storage, and electrical system upgrades to reinforce the backbone of Yukon's electricity system. Furthermore, strategic partnerships with First Nations

governments, and collaboration between Yukon government and the Yukon's public utilities are also necessary to outline the critical investments needed and the sources of grant funding that are required to keep electricity rates in the Yukon affordable in the future.

YEC also noted the need for Yukon's electricity system to get:

1. Bigger. The capacity of Yukon's electricity system needs to increase to meet the increased demands for power created by widespread electrification. The Yukon urgently needs to invest in projects that provide dependable winter capacity and the demand-side management programs that will help reduce demands on the electricity system. Upgrades to existing transmission and distribution networks, and the construction of new infrastructure like substations, is also required to make sure that Yukoners have the electricity they need when and where they need it.

2. Cleaner. More clean energy sources are needed while polluting sources are phased out. More sources of firm renewable capacity are needed to meet the increased demands for power that will come with electrification. Options for seasonal storage are also essential to convert the energy generated by intermittent renewables like solar and wind during the summer months into dependable sources of winter energy and capacity.

3. Smarter: Making Yukon's electricity system more flexible to support variable supply and demands for power, and to boost resiliency. The Yukon must continue to invest in maintaining its existing hydro resources and building the new energy storage systems (e.g., seasonal and short-term) that will provide the utilities with greater control and flexibility to manage the variable supply of renewable energy (e.g., solar, wind). Distributed energy resources, including storage and renewable generation, must be approached thoughtfully. Collaboration between government and the utilities is needed to research, plan and develop programs that deliver these resources in a manner that ensures stability and resiliency of the grid, and the universal access to affordable electricity in the Yukon. Investments in smart programs and technologies, including automated metering, are also needed to better manage and adjust when demand-side products like electric vehicle chargers, electric baseboards and water heaters, and heat pumps are used to manage their impact on system peaks. Potential interconnection with other jurisdictions should also be considered as additional opportunities to enhance

system flexibility and resiliency, expand access to other sources of non-emitting and dispatchable electricity, and grow Yukon's economy.

(b)

YEC's Dual Fuel Demand Management program is complementary to, rather than in conflict with, the Energy Branch's target of replacing 1,300 residential fossil fuel heating systems with "smart electric heating systems" as the primary heat source for the homes. The program seeks to avoid the use of electric resistance heating as a backup heat source for homes primarily heated by air-source heat pumps, particularly during times of peak demand on the power grid on cold winter days. At such times, in recent years, diesel generators have typically been the marginal source of electricity. This means any additional electrical demand is met by diesel generation. Residential space heating using electric resistance heating systems consuming electricity generated from fossil fuels is more emissions-intensive than residential space heating with fossil fuels directly. By encouraging the use of heat sources other than electric resistance heating as the backup system to air-source heat pumps, Yukon Energy's Dual Fuel Demand Management program aligns with the Yukon Government's objective of reducing the emissions intensity of residential heating in the Yukon.

(c)

As it relates to the Yukon Government's air-source heat pump rebate program, Yukon Government has confirmed that applicants in its air-source heat pump rebate program can receive a rebate under the program regardless of what backup heating systems the home has in place. There is no requirement for homeowners to remove their existing heating systems to qualify for the program.

The application form for the Yukon Government's air-source heat pump rebate program also makes no mention of requiring the removal of the home's existing heating system to qualify for the program.[1] Information regarding the presence and potential removal of an existing heating system is gathered through the application for program management and evaluation purposes. This includes whether a home's existing fossil-fuel heating system will be maintained as a back-up heat source. However, no such information is included in the program's eligibility criteria.

[1] See the Heating systems rebate application form available from the Yukon government on its website.

(d)

This analysis has not been a part of our DSM programs. Please see the response to NY-YEC-1-26 for a discussion of time of use rates, including how they work and technical barriers to their implementation in Yukon.

(e)

YEC does not have an estimate for the reduction in electricity consumption of Yukon customers with 10% or 20% rate increases. It is generally assumed that the price elasticity of demand is small because most customers are not able to respond to changes in electricity prices in the short-run.

The British Columbia Utilities Commission (BCUC) in its Decision and Order G-246-20 regarding BC Hydro's F2020 to F2021 Revenue Requirements Application found that BC Hydro's elasticity assumption of -0.1 to be reasonable. BC Hydro defines price elasticity of demand to be the measure of the responsiveness of quantity demand to a change in price and is expressed as the percent change in quantity to a one percent change in price [i.e., 1% rate increase results in a -0.1% change in consumption].

Based on BC Hydro's assumptions, a rate increase of 10% could reduce electricity consumption by 1% while 20% could reduce by 2%. This is about 10 – 20 kWh/month reduction for a typical residential customer using 1,000 kWh/month energy and 20 – 40 kWh/month reduction for a typical commercial customer using 2,000 kWh/month energy.

REFERENCE: **YEC 2021 GRA, Response to YUB--YEC-1-93, PDF pages 451-454; Application, PDF pages 256 and 259-261**

ISSUE: Capital project: Southern Lakes Storage (Marsh Lake Storage Enhancement Project)

QUOTE: YEC 2021 GRA, PDF page 180:

4. Southern Lakes Storage (Marsh Lake Storage Enhancement Project) – (forecast WIP cost of approximately $9.379 million by end of 2021 - project subject to ongoing review, potential in-service by 2023).

YEC 2021 GRA, PDF pages 182-183:

Yukon Energy completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area, and Yukoners generally; as well as a further round of First Nations engagement to confirm the position of the affected First Nations (Carcross/Tagish First Nation, Kwanlin Dun First Nation and Ta'an Kwach'an Council). Prior to the end of 2020, Yukon Energy will make a decision regarding whether to advance the project to the YESAA assessment phase.

The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in-service for the Project is 2023. (Footnote omitted.)

YEC 2021 GRA, Response to YUB-YEC-1-93(a), PDF page 452:

In 2019 and early 2020 YEC conducted a final round of public engagement regarding the project. Based on the results of this engagement and the estimated economics of the project, YEC's Board of Directors decided to advance the project into the next stage: preparing a proposal to submission to the YESAA Designated Office.

YEC 2021 GRA, Response to YUB-YEC-1-93(b)(iv), PDF page 454:

YEC is working to confirm mitigation plans for impacted properties and refine estimates to ensure costs are fully understood before moving forward with the project. Using a stagegate approach to assess a "go" or "no go" decision after more information is known from the results of

the YESAA assessment will enable a decision to be made regarding the project with refined information on the economics.

Application, PDF pages 256 and 259-261:

In November 2022, the Carcross/Tagish First Nation (CTFN) notified YEC that it would not support completion of the SLESP. As a result, YEC concluded that the project would no longer offers a net economic benefit to ratepayers as there is no reasonable probability that the project will proceed. As directed by the Board in Order 2013-01 (para 337 of Appendix A), YEC was therefore required to cease work on the SLESP project. Based on YEC's decision not to proceed further with the project, feasibility study costs to date of approximately $8.784 million will be amortized over 10 years, starting in 2023.

…

In Appendix A to Order 2018-10, the Board stated concern with the amount of time and expenditures to date with little apparent progress, and reminded YEC that if it chooses to keep developing the project that it will have the onus to demonstrate the prudence of all expenditures related to the project.

…

Based on YEC's decision not to proceed further with the SLESP project, feasibility study costs to date of approximately $8.784 million will be amortized over 10 years, starting in 2023. The table below shows costs incurred by cost element and time period, including costs accounted for by YEC's internal interest cost (AFUDC, or allowance for funds used during construction) applicable to all WIP costs.

Costs ($000's)	Inception to 2013	2014-2018	2019-2021	2022	Total	AFUDC % of Total
Third-party engineering	111	14	8	3	135	25.0%
Environmental assessment	3,974	1,973	400	131	6,478	22.1%
Project management	417	53	30	10	510	26.8%
Public consultation	125	148	320	14	607	13.5%
YEC costs	302	202	35	11	550	21.9%
Stagegate 3	-	-	388	116	504	3.2%
Total	4,928	2,391	1,181	284	8,784	20.7%
AFUDC included in Total	383	749	508	180	1,820	
AFUDC as % of Total	7.8%	31.3%	43.0%	63.4%	20.7%	

Note: "AFUDC"(Allowance for Funds Used During Construction) is YEC's internal interest cost.

Approximately $7.3 million, representing 83% of total project costs, were incurred between inception and the end of 2018, and related mostly (87%) to environmental assessment studies, engineering, and

public consultation activities plus related AFUDC interest costs. These costs were reviewed at a high level in the 2012/13 and 2017/18 GRAs.

The 2019-2021 costs were not reviewed in the 2021 GRA decision. Appendix A to Board Order 2022-03 concluded that given that the costs for the projects in WIP do not affect the test year rate base or revenue requirement, the Board made no findings regarding these projects at that time.

The 2019-2021 costs of $1.181 million consisted primarily of AFUDC interest costs on earlier environmental assessment and other costs plus some additional public consultation and the commencement of stagegate 3. Excluding related AFUDC costs, new expenditures focused on efforts to advance filing of a YESAB submission and consisted primarily of stagegate 3 costs of $0.384 million and public consultation costs of $0.286 million. YEC's internal AFUDC interest cost of $0.508 million accounted for 99% of the remaining $0.511 million costs.

The 2022 costs of $0.284 million consisted of AFUDC costs of $0.180 million and stagegate 3 costs (excluding related AFUDC) of $0.104 million incurred prior to receipt of the CTFN November letter.

QUESTION:

a) Please explain why YEC's board of directors chose to continue with the Southern Lakes Storage project despite strong indications as recent as early 2020 that it was not likely to proceed.

b) Please confirm that the Board asked YEC in YUB-YEC-1-93 about the status of the Southern Lakes Storage project in the 2021 GRA.

c) Please confirm that YEC responded in YUB-YEC-1-93 that YEC's board of directors decided to advance the project into the next stage: preparing a proposal to submission to the YESAB Designated Office. If confirmed, please provide the date the submission was made to the YESAB Designated Office and the date upon which a response was provided by the YESAB Designated Office.

d) Does YEC consider it reasonable to add AFUDC to the Southern Lakes Storage costs given that there has been no physical asset constructed?

e) Does YEC expect to earn a return on some unamortized net rate base amount related to the Southern Lakes Storage costs for 10 years notwithstanding that there has been no physical asset constructed? If so, please explain why it would be reasonable to do so.

f) When did the Kwanlin Dün First Nation and Ta'an Kwach'an Council most recently indicate and provide YEC with their respective level of support for the Southern Lakes Storage project? Were there agreements in place that indicated their level of support? Please explain fully and provide any agreement or similar substantiation of the support given.

ANSWER:

(a)

YEC completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area and Yukoners generally, as well as a further round of First Nations engagement to confirm the position of First Nations Governments in the project area (Carcross/Tagish First Nation (C/TFN), Kwanlin Dün First Nation (KDFN) and Ta'an Kwach'an Council (TKC)).

As reported in response to YUB-YEC-1-93 in the 2021 GRA, based on the results of the public engagement in 2019 and early 2020 regarding the project and the estimated economics of the project, YEC's Board of Directors in Q2 2020 decided to advance the project into the next stage: preparing a proposal for submission to the YESAA Designated Office.

In summary, YEC's Board of Directors concluded in 2020 that the project still had a reasonable possibility of proceeding based on the information that was available at that time, and that there was not a reasonable basis to justify terminating the project. The Board of Directors' evaluation that the project had a reasonable possibility of proceeding did not change until C/TFN subsequently notified YEC in November 2022 that it would not support completing the project.

(b)

Confirmed.

(c)

Confirmed that YEC's response to YUB-YEC-1-93 in its 2021 GRA proceeding referred to the Board of Directors decision in 2020 to advance the project into the next stage of preparing a proposal for submission to the YESAB Designated Office. In accordance with that decision, work commenced to prepare a submission. Ultimately, however, that work was not completed, and no submission for the SLESP was made to the YESAB Designated Office prior to the C/TFN notifying YEC that it would not support completing the project.

(d)

Yes. AFUDC costs are reasonably included in costs for terminated projects where, by definition, there has been no physical asset constructed. By way of example, YEC's costs to September 2014 for the terminated Gladstone Diversion project, including AFUDC costs to that date, were approved by Board Order 2018-10 for amortization over 10 years (see Section 6.1.4.6 of Appendix A to Board Order 2018-10 for Board ruling, and response to UCG-YEC-1-34 in the 2017-18 YEC GRA proceeding for breakdown of project costs including AFUDC). This treatment is also consistent with section 4 of its Finance Policy FA-016, which was the PCAP approved by the Board in Order 2018-10 (see p. 238 of the PDF for YEC's 2017-2018 GRA (Appendix 5.1), and Borad Order 2018-10, Appendix A at pars. 539-540).

Accordingly, it is reasonable to include AFUDC costs in prudently incurred project costs to the date when the project is stopped.

(e)

Yes, for the reasons described in response to question (d).

(f)

The response to “a” above reviews YEC’s engagement with all parties, including Kwanlin Dün First Nation (KDFN) and Ta’an Kwach’an Council (TKC), in 2019 and early 2020 regarding the project, and the subsequent YEC decision to move to a next stage with the project.

Engagement with KDFN and TKC (as well as C/TFN) related to the project continued thereafter in 2021 and 2022 to prepare a possible YESAB submission. Prior to engagement that started in later 2021 between the C/TFN, KDFN, TKC, Yukon government, and YEC on the Whitehorse Rapids Generating Station (WRGS) Project (as outlined below), YEC’s focus with KDFN and TKC was on ways to work together on planning the proposed SLESP. No agreement was sought or secured during this period to determine their respective level of support.

On evolution of process regarding SLESP in 2021, the following are noted. By August 2021, YEC had been informed that work on SLESP was overlapping with work needed on the WRGS relicensing, and that this was leading to confusion, duplication of work, and issues for First Nation resource capacity for engagement. YEC’s Board as a result in August 2021 approved halting the separate current SLESP stagegate scope of work and approving that ongoing SLESP fieldwork be completed as part of the WRGS relicensing project (on the understanding that SLESP would continue to be reviewed as a potential option for WRGS relicensing). In December 2021, YEC’s Board approved, based on information available at that time, ongoing work scope and budget for WRGS relicensing that included pursuit of the SLESP amendments in the assessment of the WRGS relicensing. This work continued in 2022 until, as described at pages 5.2A-30/31 of the Application, YEC’s decision to cease work on the SLESP following C/TFN’s request at the October 31, 2022 meeting that the SLESP changes be removed from the WRGS relicensing application.

REFERENCE: **Application, PDF page 513**

ISSUE: Return on Investment

QUOTE: A final decision is expected regarding the GCOC proceeding before the completion of Yukon Energy's GRA Application proceeding. YEC proposes that the benchmark ROE be adjusted to align with the final BCUC decision for the benchmark utility.

QUESTION:

a) If a decision is rendered for the BC Utilities Commission (BCUC) GCOC proceeding before the close of the oral hearing for this Application, does YEC intend to amend the ROE portion of its Application based on that decision? Please explain.

b) Does YEC commit to placing a copy of the relevant BCUC decision on the record of this proceeding if YEC amends its Application?

ANSWER:

(a)

Yes. A decision has been released by the BCUC on the Stage 1 proceeding (Order G-236-23) approving an ROE of 9.65% for both FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC), however the decisions on any benchmark utility are yet to be determined. This will be determined in the BCUC GCOC Stage 2 proceeding expected to be completed in 2024, but not necessarily before the close of the oral hearing on YEC's Application. Prior to the oral hearing on YEC's Application, the Board will review this same Stage 1 BCUC decision and related ROE issues in the oral hearing on the AEY GRA application.

(b)

A copy of the relevant recent Stage 1 BCUC decision (Order G-236-23) is provided in YUB-YEC-1-84 Attachment 1.

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British Columbia Utilities Commission

Generic Cost of Capital Proceeding

(Stage 1)

Decision
and Order G-236-23

September 5, 2023

Before:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

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EXECUTIVE SUMMARY

The British Columbia Utilities Commission (BCUC), pursuant to section 59(5)(b) of the *Utilities Commission Act* (UCA) is responsible for ensuring that shareholders of the utilities it regulates are afforded a reasonable opportunity to earn a fair return on their invested capital.

On January 18, 2021, the BCUC noted that significant time had passed since the BCUC's 2013 and 2016 cost of capital reviews and over that period, changes have occurred in financial markets, and pursuant to section 82 of the UCA, issued a Notice of Initiating a Generic Cost of Capital (GCOC) Proceeding.

The BCUC determined that a two-stage proceeding to establish public utilities' cost of capital was appropriate for the GCOC proceeding. Stage 1 of the GCOC proceeding will determine the deemed capital structure and allowed return on equity (ROE) of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC). Stage 2 will determine matters related to the benchmark utility, including whether utilizing a benchmark utility remains an appropriate approach and, if so, whether one or both or neither of these utilities should serve as a benchmark for establishing the cost of capital for other utilities in British Columbia (BC).

FEI and FBC jointly engaged Mr. James Coyne (Mr. Coyne) of Concentric Energy Advisors Inc. (Concentric) as their expert consultant in Stage 1 of the GCOC proceeding. The BCUC engaged Dr. Jonathan A. Lesser (Dr. Lesser) of Continental Economics, Inc. (Continental Economics) as an independent expert. Dr. Lesser opined on Mr. Coyne's expert analysis. Dr. Lesser did not perform his own independent calculations and did not present capital structure or ROE recommendations. No Intervener engaged an expert to provide expert evidence on FortisBC's cost of capital.[1]

Key Principles

The purpose of Stage 1 of the GCOC proceeding is to set a fair return for FEI and FBC. When determining the utilities' cost of capital, the Panel is guided by certain fundamental regulatory principles, including the Fair Return Standard which requires three elements to be met for a fair and reasonable return on capital:

a) The comparable investment requirement – the return on capital should be comparable to the return available from the application of the invested capital to other enterprises of like risk;

b) The financial integrity requirement – the return on capital should enable the financial integrity of the regulated enterprise to be maintained; and

c) The capital attraction requirement – the return on capital should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle. That principle provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding

[1] Corix Multi-Utility Service Inc., Pacific Northern Gas Ltd and Pacific Northern Gas (N.E.) submitted a Brattle Report on the use of a Benchmark Utility (Exhibits B6-4 and B9-5).

company structure. The BCUC had noted the relevance of the standalone principle in past cost of capital decisions, and we continue to adhere to this principle to determine FEI and FBC's cost of capital in this proceeding.

Informed judgment, with the support of quantitative and qualitative evidence made available to us during the proceeding, plays a significant role in determining the appropriate cost of capital for each of the two utilities. Therefore, by necessity, certain aspects of our decision are as much art as science.

Approach to the Cost of Capital Determination

When determining the cost of capital and the allowable return, there are four key elements that the Panel considers:

1. The actual returns of a proxy group of peer utilities.
2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies.
3. The credit ratings of FEI and FBC.
4. The results of various financial models that are designed to assess how the market prices risk and considers earnings in the evaluation of cost of capital.

Not one of the above elements is, in itself, determinative. Rather, the Panel considers all of these elements together, applying an appropriate weight to each of them as it determines the allowed cost of capital.

The Panel also makes determinations on "adders" to the ROE as applied for by FortisBC to account for flotation costs incurred by the parent company and for the need for "financial flexibility", again based on consideration of the above elements.

Consideration of Peer Data Set

To provide appropriate comparators for the allowed ROE and capital structure for FEI and FBC, the Panel determined a "proxy group" of peer companies that are both publicly traded and comparable to FEI and FBC's business and financial characteristics in order to assess each company's data. FortisBC and its expert, Mr. Coyne, presented proxy group data from both United States (US) and Canadian gas utilities and also combined these US and Canadian utilities into a North American proxy group. We agree with Mr. Coyne that some of the companies in his Canadian proxy group would not pass the same screening criteria he applied to his US proxy groups. The Panel finds merit in using a combined North American proxy group and removing certain non-qualifying Canadian utilities.

The Panel was presented with three sets of data during the proceeding, starting with December 2021 data when FortisBC filed its evidence and last updated in October 2022. The Panel is persuaded about the reasonableness of using the October 2022 market data, being the most recent publicly available data, to inform its establishment of an appropriate cost of capital.

Business Risks and Credit Ratings

Given the impact of business risk on utilities' expected return, the Panel reviews this from the perspective of the shareholder, as it is an important consideration for investors when making their investment decisions. Part of this review includes investors' consideration of credit ratings and changes in business risks.

Overall, the Panel finds that FEI's overall business risk to the shareholder has increased since 2016 while FBC's business risk has not changed materially for the shareholder since 2013. However, the Panel considers FEI and FBC's current credit ratings satisfactory for maintaining the financial integrity of each respective utility and that FEI and FBC do not require an improvement in those credit ratings for each utility to continue to attract capital on reasonable terms.

Financial Models

Regulators typically rely on financial models in their determination of an approved ROE because the actual cost of equity for a regulated utility cannot be observed. All models are simplifications of reality, using simplifying assumptions and as such, each model is subject to varying degrees of criticism. Quantitative models produce a range of reasonable results from which the ROE is selected.

The Panel considers three financial models:

1. The Capital Asset Pricing Model (CAPM), based on the relationship between non-diversifiable risk and expected return;
2. The Discounted Cash Flow (DCF), based on the premise that today's stock price represents investors' expectations regarding future cash flows from holding that stock, in terms of dividends and price appreciation; and
3. The Risk Premium Model, based on the premise that common equity capital is riskier than debt and, therefore, equity investors require a greater return than would debtholders.

For the CAPM, Mr. Coyne and Dr. Lesser have different opinions on how to estimate the key variables of risk-free rate and market risk premium (MRP), as well as the data sources for the beta coefficients, a measure of the risk of a security relative to the market. After examining the evidence and considering the views of the experts, we determine that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields is reasonable, his data sources and averaging of adjusted data to estimate betas are acceptable, and his method to forecast the MRP, including a 50:50 weighting of historic and forward MRPs, sufficiently balances and moderates the assumption of higher analyst expectations over the next five years with the actual achieved MRPs over a long history. As a result, we are not relying on the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's preferred approach.

The Panel uses a CAPM ROE, exclusive of an adder for flotation costs and financial flexibility, of 9.90 percent for FEI and 9.77 percent for FBC, respectively, after removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group, as it weights the results of the different ROE models in the overall determination.

For the DCF model, Mr. Coyne presented two versions of the model: a constant DCF model and a Multi-Stage DCF model, consisting of three stages. Mr. Coyne only uses the latter's results in his ROE recommendations. Both experts agree on the merits of using the Multi-Stage DCF model. Consistent with the BCUC's preferred approach in the last two GCOC proceedings, the Panel finds that a Multi-Stage DCF model is preferable to a Constant Growth DCF model because the former allows for recognition that the proxy utility companies' dividend growth rates may not perform the same in different time horizons. Also, since no interveners commented on the pros and cons of using a two-stage versus a three-stage DCF model and most of them supported the three-stage DCF model presented by Mr. Coyne, the Panel finds it reasonable to use a three-stage DCF model to estimate the ROE for FEI and FBC, with each of the first two stages lasting five years.

Furthermore, both experts are aligned on key aspects of the multi-stage DCF analysis such as using recent average stock prices to calculate the dividend yield, forecast growth in earnings rather than dividend growth rates, and analysts' estimates for forecast earning growth rates. However, the two experts disagree on the data sources for the dividend growth rates in the first and third stage. After examining the evidence and considering the views of the experts, the Panel finds that using multiple sources for the analysts' forecasts of earnings growth rates is better than using a single source, as averaging can mitigate the impact of any one forecast. In the third stage, the Panel finds that using the gross domestic product (GDP) price deflator would be better than using consumer price index (CPI) to derive nominal GDP growth rates because the GDP price deflator is more representative of the market as a whole than CPI. However, as no evidence was presented using the GDP deflator, the Panel reluctantly accepts the use of CPI as a reasonable forecast to be used in the determination of long-term growth rates, while noting that the use of CPI may result in an overstated ROE. In the end, the Panel accepts Dr. Lesser's submission that the difference between the two would likely not be determinative in setting the ROE. As for the second (transition) stage, the Panel accepts the methodology employed by Mr. Coyne to transition between the first stage and the third stage growth rates.

The Panel uses a multi-stage DCF ROE, exclusive of an adder for flotation costs and financial flexibility, of 8.93 percent for FEI and 8.99 percent for FBC, respectively, after removing Enbridge Inc. and Canadian Utilities Limited from the North American proxy groups, as it weights the results of the different ROE models in the overall determination.

In the Panel's view, relying on more models is especially important at times when the pure market-based models like the DCF and the CAPM tend to get whipsawed by volatility in the market. The Panel finds that considerable weight should be given to the use of a Risk Premium Model for the purposes of determining the appropriate ROE for FEI and FBC given the recent volatility in the market and economic conditions.

The Panel notes that the Federal Energy Regulatory Commission has recognized the theoretical validity and value of the Risk Premium Model, as it has adopted that model along with the CAPM and DCF models, which it weights equally for determining the cost of capital for regulated electric transmission companies in the US. The Panel uses a Risk Premium Model ROE of 10.12 percent for FEI and 10.16 percent for FBC, respectively, as it weights the different ROE models in the overall determination.

Ultimately, the Panel finds that assigning an equal weighting to each of the three financial models is appropriate to determine the approved ROE for FEI and FBC.

Overall Determinations

The Panel finds that the appropriate way to account for required financial flexibility is in the context of determining the appropriate capital structure.

The Panel accepts that any reasonable and prudently incurred flotation costs incurred by a public utility are recoverable from ratepayers, over and above the approved costs of capital. However, there is no evidence before the Panel that FEI or FBC incurs any flotation costs and therefore there are no costs to recover. FEI and FBC can request recovery of actual costs incurred by the parent company by providing applicable invoices or other supporting documentation from the parent when FEI and FBC issue additional equity. Those expenditures, if and as incurred, can be considered for recovery from the ratepayers of FEI or FBC through review and approval as part of each utility's revenue requirement process.

The Panel finds that 45.0 percent equity thickness for FEI meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by the Panel's assessment of FEI's business risk.

The Panel finds that a modest upward adjustment of 1.0 percent for financial leverage and flexibility for FBC is warranted to conform with the Fair Return Standard. The Panel determines that the deemed equity component for FBC is 41.0 percent.

Based on the evidence examined and submissions received in Stage 1 of the GCOC proceeding, the Panel determines the following equity component in the deemed capital structure and allowed ROE will meet the Fair Return Standard:

- For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and
- For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.

Effective Date

The Panel determines that the deemed capital structure and allowed ROE for FEI and FBC as set out in this decision be implemented, effective January 1, 2023. Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.

FEI is the current benchmark (Benchmark Utility) for other utilities in BC that use a Benchmark Utility to set their rates. The Panel notes it would be unfair for these utilities to retrospectively collect or refund customer monies without an appropriate mechanism for doing so or without adequate notice to ratepayers. However, while each utility's situation may be unique, some balance must be factored in to ensure consistency and fair treatment amongst all utilities. In terms of specific mechanism, the Panel considers that the benefits of establishing interim rates for all other utilities that use a Benchmark Utility to set their capital structure, along with equity return, outweigh other mechanisms.

The Panel directs that interim rates, effective January 1, 2024, be established on a refundable or recoverable basis for all other utilities, except FBC, that currently use the Benchmark Utility to set each utility's capital structure and equity return, pending the BCUC's final decision on Stage 2 of the GCOC proceeding. The Panel confirms Stage 2 of the GCOC proceeding will commence 60 days after the date of this decision.

1.0 INTRODUCTION

1.1 Background

The British Columbia Utilities Commission (BCUC), pursuant to section 59(5)(b) of the *Utilities Commission Act* (UCA) is responsible for ensuring that shareholders of the utilities it regulates are afforded a reasonable opportunity to earn a fair return on their invested capital.

On October 11, 2012, the BCUC established that FortisBC Energy Inc. (FEI) would serve as the benchmark (Benchmark Utility) for any other utility in British Columbia (BC) that uses a Benchmark Utility to set rates.[2] FEI's common equity component was set at 38.5 percent and its return on equity (ROE) was set at 8.75 percent, effective January 1, 2013.[3] On March 25, 2014, the BCUC set the common equity component or equity ratio of the capital structure and equity risk premium over the Benchmark Utility for other regulated utilities in the province.[4] FortisBC Inc. (FBC) was one of the regulated utilities and a full review of its capital structure and equity risk premium was undertaken as part of that proceeding.[5] The BCUC determined that an equity ratio of 40 percent and an equity risk premium of 40 basis points (bps)[6] over the Benchmark Utility for FBC was appropriate.[7] Subsequently, on August 10, 2016, the BCUC reaffirmed FEI's cost of capital.[8] The BCUC also suspended use of the automatic adjustment mechanism formula previously approved in 2013.

By letter dated January 18, 2021, the BCUC noted that significant time had passed since the BCUC's 2013 and 2016 cost of capital reviews and over that period, changes have occurred in financial markets, and pursuant to section 82 of the UCA, issued a Notice of Initiating a Generic Cost of Capital (GCOC) Proceeding.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

Purpose of the Proceeding

The purpose of the GCOC proceeding is to establish a method to determine the appropriate cost of capital for regulated utilities in BC[9], as well as to review the appropriateness of continuing the use of a Benchmark Utility, and if so, the appropriate cost of capital for the benchmark.

[2] BCUC 2013 GCOC, Order G-148-12 with Reasons for Decision dated October 11, 2012, Directive 1.
[3] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013, Directives 1 and 2.
[4] BCUC 2013 GCOC Stage 2, Order G-47-14 and Decision dated March 25, 2014 (2014 Decision), Directives 1 to 6.
[5] 2014 Decision, pp. 4, 60–87.
[6] 1 basis point = 0.01 percent.
[7] 2014 Decision, p. 86.
[8] FEI Application for its Common Equity Component and Return on Equity for 2016 (FEI 2016 COC), Order G-129-16 and Decision dated August 10, 2016 (2016 Decision), Directives 1 and 2.
[9] Order G-156-21 with Reasons for Decision.

Two-Stage Proceeding

By Order G-156-21, the BCUC determined that a two-stage proceeding to establish public utilities' cost of capital was appropriate for the GCOC proceeding, where Stage 1 sets the benchmark ROE (Benchmark ROE) based on a Benchmark Utility, and Stage 2 uses a generic methodology for each utility to determine its unique cost of capital in reference to the Benchmark Utility.[10] Hereafter, Stage 1 refers to the first stage of the GCOC proceeding and Stage 2 refers to the second stage of the same proceeding.

By Order G-205-21, the BCUC determined that the review of deferral account financing costs, as well as any other matters that may arise out of Stage 1 and Stage 2 should be within the scope of the GCOC proceeding, after the completion of Stage 2.[11]

By Order G-281-21, the BCUC found that it was appropriate and efficient to first determine the cost of capital for FEI and FBC, collectively FortisBC, as both utilities are the largest investor-owned natural gas and electric utilities, respectively, in BC.[12] Pursuant to Order G-281-21, and as amended by Order G-288-21, FortisBC filed its evidence for FEI and FBC.[13] By Order G-106-22, the BCUC confirmed that the decision on FEI and FBC's capital structure and ROE will be determined first in Stage 1, and then the BCUC would move onto reviewing which, if any, of the utilities will be the Benchmark Utility in Stage 2.[14]

Order G-106-22 also sets out the scope of Stage 1 as follows:[15]

1. The determination of the allowed ROE and deemed capital structure of FEI and FBC, and the effective dates for which FEI and FBC's cost of capital will take effect.

2. Whether re-establishment of a formulaic ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is warranted, then:

    a) The specifications of the ROE AAM formula.

    b) The frequency that the ROE AAM will apply (i.e. annually or some other frequency) and to whom the ROE AAM will apply.

    c) The date for which the ROE AAM will take effect.

3. The criteria, off-ramps, or other triggers to warrant a future cost of capital proceeding.

4. Any other items that may arise during the proceeding to be considered in Stage 1.

[10] Order G-156-21 with Reasons for Decision dated May 21, 2021
[11] Order G-205-21 with Reasons for Decision dated July 7, 2021
[12] Order G-281-21 with Reasons for Decision dated September 24, 2021, p.6. , Order G-156-21 with Reasons for Decision dated May 21, 2021, Appendix A, p. 7
[13] Exhibit B1-8, p. 1.
[14] Order G-106-22 dated April 21, 2022.
[15] Ibid.

FortisBC Proposal

In its evidence dated January 31, 2022, FortisBC proposes the following deemed capital structure and ROEs for FEI and FBC, respectively: [16]

- For FEI, a common equity ratio of 45 percent with an ROE of 10.1 percent representing an increase from FEI's current common equity ratio of 38.5 percent and ROE of 8.75 percent; and
- For FBC, a common equity ratio of 40 percent with an ROE of 10.0 percent representing an increase from FBC's current ROE of 9.15 percent, with no change to its common equity ratio.

1.3 Regulatory Process

Stage 1 included a BCUC public hearing process involving the participation of experts in the cost of capital field and several participants, including regulated utilities and interveners.

Experts

Two experts figured prominently in Stage 1: FEI and FBC jointly engaged Mr. James Coyne (Mr. Coyne) of Concentric Energy Advisors Inc. (Concentric) as each utility's expert consultant. The BCUC engaged Dr. Jonathan A. Lesser (Dr. Lesser) of Continental Economics, Inc. (Continental Economics) as an independent expert.

Dr. Lesser's involvement in Stage 1 includes submissions of consultant reports, responses to information requests (IRs) and participation in the oral hearing. Dr. Lesser opined on Mr. Coyne's expert analysis. Dr. Lesser did not perform his own independent calculations and did not present capital structure and ROE recommendations. No intervener engaged an expert to provide expert evidence on FortisBC's cost of capital.[17]

Application Review Process

In accordance with the regulatory timetable established by the BCUC, the BCUC undertook a comprehensive public review process, including the following:

- BCUC Consultant, Dr. Lesser's of Continental Economics consultant report (filed as Exhibit A2-3): "Continental Economics, Inc. Dr. Jonathan A. Lesser Regulated Utility Cost of Capital: Theory and Canadian Practice Report dated August 4, 2021." (Dr. Lesser's Report)[18]
- One round of utilities and interveners' IRs on the BCUC consultant, Dr. Lesser 's Report
- Filing of evidence by FBC and FEI, including evidence of Mr. Coyne (Mr. Coyne Evidence)[19] of Concentric (FortisBC's Evidence)
- Two rounds of IRs on FortisBC's Evidence

[16] Exhibit B1-8, p. 1.
[17] Corix Multi-Utility Service Inc., Pacific Northern Gas Ltd and Pacific Northern Gas (N.E.) submitted a Brattle Report on the use of a benchmark utility (Exhibits B6-4 and B9-5).
[18] Exhibit A2-3, Continental Economics Inc., "Regulated Utility Cost of Capital: Theory and Canadian Practice" by Dr. Lesser dated August 4, 2021.
[19] Exhibit B1-8, Appendix C, Evidence of Mr. James Coyne, Concentric Energy Advisors Inc., Regarding the Cost of Capital Estimation.

- IR No. 2 to Dr. Lesser regarding Mr. Coyne's Evidence
- Filing of FortisBC's Rebuttal Evidence
- One round of IRs on FortisBC's Rebuttal Evidence
- Update to Mr. Coyne's Model
- Two procedural conferences held on April 14, 2022 and July 8, 2022
- Oral hearing held from November 7, 2022 to November 9, 2022
- Undertakings to the oral hearing
- FortisBC's Final Argument filed by December 23, 2022
- Final arguments from interveners filed by January 27, 2023
- FEI's Reply Argument filed by February 21, 2023

After the filing of arguments, on May 8, 2023, the BCUC invited parties to make submissions on the effective date for all other utilities that use the Benchmark Utility to set their capital structure and equity return.[20] Written submissions from parties were received by May 31, 2023 and replies were received by June 14, 2023.

Registered Utilities and Interveners

Public utilities regulated by the BCUC were categorized as either *Affected Utilities* or *Other Utilities*. The Affected Utilities were designated given each utility's active participation in previous cost of capital proceedings that set a benchmark ROE or the anticipated interest of each utility in the GCOC proceeding as investor-owned utilities. These Affected Utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. Other Utilities were also expected to participate as applicants in the GCOC proceeding.

The following Affected Utilities participated in the GCOC proceeding:

- FEI
- FBC
- Corix Multi Utility Services Inc. (Corix)
- Pacific Northern Gas Ltd. (PNG)

The following Other Utilities participated in the GCOC proceeding:

- FortisBC Alternative Energy Service Inc. (FAES)
- Nelson Hydro
- Kyuquot Power Ltd. (KPL)

[20] Exhibit A-31.

- Creative Energy Vancouver Platforms Inc. (Creative Energy)
- River District Energy (RDE)

The following parties registered as interveners:

- Residential Consumer Intervener Association (RCIA)
- Movement of United Professionals (MoveUP)
- Clean Energy Association of BC (CEABC)
- Association of Major Power Customers of BC (AMPC)
- Industrial Customers Group (ICG)
- Commercial Energy Consumers Association of British Columbia (the CEC)
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO)
- British Columbia Hydro and Power Authority (BC Hydro)
- Boralex Ocean Falls Limited Partnership (Boralex)

2.0 KEY PRINCIPLES AND DECISION FRAMEWORK

Fair Return Standard

The purpose of Stage 1 is to set a fair return for FEI and FBC. When determining the utilities' cost of capital, the Panel is guided by certain fundamental regulatory principles, including the Fair Return Standard, where the BCUC has a duty to approve rates that will provide the utilities' shareholders a reasonable opportunity to earn a fair return on their invested capital.[21] The Supreme Court of Canada established the principles surrounding the concept of "fair return" for a regulated company in *Northwestern Utilities Limited v. City of Edmonton*[22]:

> The duty of the [National Energy] Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. (per Lamont J.)

The Fair Return Standard, as discussed in the National Energy Board's Decision,[23] is fundamental to cost of equity proceedings and requires three elements to be met for a fair and reasonable return on capital:

[21] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013 (2013 Decision), p. 12.
[22] [1929] S.C.R. 186.
[23] TransCanada PipeLines Limited, RH-2-2004 at p. 17.

a) The comparable investment requirement – the return on capital should be comparable to the return available from the application of the invested capital to other enterprises of like risk;

b) The financial integrity requirement – the return on capital should enable the financial integrity of the regulated enterprise to be maintained; and

c) The capital attraction requirement – the return on capital should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

All three standards must be met, and none ranks higher in priority to the others.

Standalone Principle

In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle.[24] Mr. Coyne explains that the standalone principle provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding company structure.[25] The BCUC had noted the relevance of the standalone principle in past cost of capital decisions and we continue to adhere to this principle to assess FEI and FBC's cost of capital in this proceeding.

Relevance of Past BCUC Decisions

While past BCUC decisions are informative and provide historical context, they are not determinative in this GCOC Stage 1 Decision. We must evaluate the evidence presented in the current proceeding. The use of comparable proxy peers and financial models play a large part of this proceeding, where that evidence was explored extensively by the two cost of capital experts, the BCUC and interveners. FEI and FBC's respective business risks and credit rating information were also similarly tested as part of this proceeding.

Informed judgment, with the support of quantitative and qualitative evidence made available to us during the proceeding, plays a significant role in determining the appropriate cost of capital for each of the two utilities. Therefore, by necessity, certain aspects of our decision are as much art as science.

Decision Framework

We structure the remainder of our decision as follows:

- Section 3.0 provides an overview of the peer data and the timeframe to use that are relevant to our ROE determinations with proxy group data guiding our capital structure determinations.
- Section 4.0 discusses the business risk changes for FEI and FBC from the shareholders' perspective since the BCUC's last assessment of this issue, and the impact this may have on the utilities' overall capital structure.

[24] 2013 Decision, pp. 96, 100.
[25] Exhibit B1-8-1, Appendix C, p. 11.

- Section 5.0 reviews financial modelling analyses presented by Mr. Coyne and the expert evidence of Dr. Lesser.
- Section 6.0 summarizes all the relevant evidence and the Panel's various findings to arrive at a final determination on FEI and FBC's capital structure and ROE and applies a reasonableness check on same.
- Section 7.0 establishes the effective date of our determinations and the timing of Stage 2. Section 8.0 addresses other issues raised during this proceeding.

2.1 Legislative Requirement

The BCUC, pursuant to section 59 of the UCA, is responsible for establishing rates that are not unjust, unreasonable, unduly discriminatory or unduly preferential:

> 59 (1)A public utility must not make, demand or receive
>
> (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
>
> (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

Pursuant to section 59 (5), a rate is "unjust" or "unreasonable" if the rate is:

> (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason.

In discharging its duty under section 59 of the UCA, the BCUC must at the same time give effect to the regulatory compact by ensuring that shareholders of the regulated utilities are afforded a reasonable opportunity to earn a fair return on their invested capital, otherwise commonly referred to as cost of capital.

2.2 Approach to the Cost of Capital Determination

When determining the cost of capital and the allowable return, there are four key elements that the Panel considers:

1. The actual returns of a proxy group of peer utilities.
2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies.
3. The credit ratings of FEI and FBC.
4. The results of various financial models that are designed to assess how the market prices risk and considers earnings in the evaluation of cost of capital.

Not one of the above elements is, in itself, determinative. Rather, the Panel considers all of these elements together, applying an appropriate weight to each of them as it determines the allowed cost of capital.

The Panel also makes determinations on "adders" to the ROE applied for by FortisBC to account for flotation costs incurred by the parent company and for the need for "financial flexibility", again based on consideration of the above elements.

3.0 CONSIDERATION OF PEER DATA SET

To provide appropriate comparators for the allowed ROE and capital structure for FEI and FBC, our first task is to determine a group of peer companies with ROE data that is readily available. Therefore, we look to publicly traded companies that have business and financial characteristics comparable to those of FEI and FBC to serve as a "proxy" for purposes of the ROE estimation process.

The following sections examine the possible alternatives presented in this proceeding: a Canadian proxy group, a US proxy group, and a North American proxy group. It also discusses the timing of the data sets on which to base the determination of the ROE.

3.1 Consideration of US Data

Mr. Coyne submits that several Canadian regulators, including the BCUC, have recognized the integrated nature of Canadian and US financial markets, that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly traded utilities. As a result, Canadian regulators have adopted a pragmatic view of the use of US data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. Mr. Coyne notes that in its last GCOC decision, the BCUC affirmed the reasonableness of using US market data and proxy groups.[26]

3.2 Proxy Group Selection

Both Mr. Coyne and Dr. Lesser agree with the need to establish a proxy group of companies for the Panel to consider when it determines an appropriate ROE for FEI and FBC. While Mr. Coyne and Dr. Lesser's respective approaches may have differed on the criteria used to select the firms in the proxy group, ultimately, Dr. Lesser "withdrew" his evidence on proxy groups during cross-examination and supported using Mr. Coyne's proxy groups.[27]

Mr. Coyne developed five proxy groups for his ROE analysis (see Table 1). He notes that the selected companies possess a set of business and financial attributes that are similar to FEI and FBC's regulated gas and electric utility operations, thus providing a reasonable basis for ROE and capital structure estimates.

The Canadian proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Due to their limited number, the only screening criterion was an investment grade credit rating, which all companies in the utility sector possess. In contrast, to create a group of essentially pure-play US gas

[26] Exhibit B1-8-1, Appendix C, pp. 37–38.
[27] Transcript Volume 4, p. 421.

and electric utilities with similar risk profiles to FEI and FBC respectively, Mr. Coyne applied the screening criteria discussed below.

He explains that the utilities must:[28]

- Have credit ratings of at least BBB+ from Standard &Poor's Global Ratings (S&P) or Baa1 from Moody's Investors Service (Moody's);
- Consistently pay quarterly cash dividends;
- Have positive earnings growth rate projections from at least two sources;
- Derive at least 65 percent (gas proxy) or 70 percent (electric proxy) of operating income from regulated operations in the period from 2018 to 2020;
- Derive at least 90 percent of regulated operating income from natural gas distribution (gas proxy) or electric (electric proxy) utility service in the period from 2018 to 2020; and
- Not have been involved in a merger or other significant transformative transaction during the evaluation period.

Table 1: Proxy Groups Companies[29]

Company	Canadian Utilities	U.S. Gas Utilities	U.S. Electric Utilities	N.A. Gas Utilities	N.A. Electric Utilities
Algonquin Power and Utilities Corp.	✓				✓
AltaGas Ltd.	✓			✓	
Canadian Utilities Limited	✓			✓	✓
Emera Inc.	✓				✓
Enbridge, Inc.	✓			✓	
Hydro One, Ltd.	✓				✓
New Jersey Resources Corporation		✓		✓	
Northwest Natural Gas Company		✓		✓	
ONE Gas, Inc.		✓		✓	
Spire, Inc.		✓		✓	
Alliant Energy Corp.			✓		✓
American Electric Power Company			✓		✓
Duke Energy Corporation			✓		✓
Entergy Corporation			✓		✓
Exelon Corp			✓		✓
Evergy Inc.			✓		✓
NextEra Energy Inc.			✓		✓
OGE Energy Corporation			✓		✓
Pinnacle West Capital Corp.			✓		✓
Portland General Electric Company			✓		✓

[28] Exhibit B1-8-1, Appendix C, pp. 37, 39–42.

[29] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Figures 18-22, pp. 40–43.

As shown in Table 1, there is only one Canadian proxy group, comprised of six companies that are a combination of both gas and electric companies. For the US proxy groups, four US gas distribution utility companies and 10 US electric companies met the respective screening criteria. Mr. Coyne then created North American proxy groups by combining the Canadian and US regulated utilities. On the gas side, he chose the three Canadian regulated utilities that have significant natural gas operations, plus the US gas proxy companies. For the electric side, he selected the four Canadian regulated utilities that are primarily electric companies, plus the US electric proxy companies.[30]

Table 2 and Table 3 compare FEI and FBC with the Canadian and US proxy companies on key metrics such as size (as measured by market capitalization), revenues, assets, and the share of regulated income.

Table 2: Canadian and US Gas Utilities[31]

Canadian Utilities	**Market Cap (Can$ million) as of 12/31/21**	**Total revenue (Can$ million) as of 12/31/20**	**Total assets (Can$ million) as of 12/31/20**	**Regulated income/total income (%)[32]**
FEI	n.a.	1,385[33]	7,738[34]	100%[35]
AltaGas Ltd.	7,651	5,587	21,532	140%
Canadian Utilities Limited[36]	9,878	3,233	20,296	64%
Enbridge Inc.	100,103	39,087	160,276	16%
U.S. Utilities	**US$ million**	**US$ million**	**US$ million**	**Regulated gas income/total reg income (%)**
New Jersey Resources Corporation	3,940	1,954	5,570	101%
Northwest Natural Gas Company	1,495	759	3,599	91%
ONE Gas, Inc.	4,158	1,530	6,029	100%
Spire, Inc.	3,375	1,855	8,241	100%

[30] Exhibit B1-8-1, Appendix C, pp. 41–42.

[31] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Exhibit JMC-FEI-3, pp. 1–2.

[32] Source: Company 10-K reports, average of three most recent years.

[33] Exhibit B1-8-1, Appendix C, Figure 47, p. 107.

[34] Ibid., Appendix D, pdf p. 472.

[35] Ibid., Appendix C, p. 112.

[36] Canadian Utilities Limited is a combination electric and gas utility. Earnings are 53.3% electric and 46.7% gas; Assets are 56.4% electric and 43.6% gas; and revenues are 47.1% electric and 52.9% gas.

Table 3: Canadian and US Electric Utilities[37]

Canadian Utilities	Market Cap (Can$ million) as of 12/31/21	Total revenue (Can$ million) as of 12/31/20	Total assets (Can$ million) as of 12/31/20	Regulated income/total income (%)
FBC	n.a.	412[38]	2,437[39]	100%[40]
Algonquin Power and Utilities Corp.	12,276	2,249	16,850	86%
Canadian Utilities Limited	9,878	3,233	20,296	64%
Emera Inc.	16,432	5,506	31,234	92%
Hydro One, Ltd.	19,687	7,290	30,294	100%
U.S. Utilities	**US$ million**	**US$ million**	**US$ million**	**Reg. electric income/total reg income (%)**
Alliant Energy Corp.	15,390	3,416	17,710	91%
American Electric Power Company	44,810	14,919	80,757	100%
Duke Energy Corporation	80,668	23,453	162,388	91%
Entergy Corporation	22,641	10,114	58,239	99%
Exelon Corp	56,418	33,039	129,317	91%
Evergy Inc.	15,574	4,913	27,115	100%
NextEra Energy Inc.	183,185	17,997	127,684	100%
OGE Energy Corporation	7,683	2,122	10,719	100%
Pinnacle West Capital Corp.	7,964	3,587	20,020	100%
Portland General Electric Company	4,732	2,145	9,069	100%

In Mr. Coyne's view, the US gas and electric proxy groups are more comparable to FEI and FBC, respectively, in terms of business risk than the Canadian proxy group utilities, many of which have significant non-gas or non-electric operations and unregulated operations.[41] In response to Dr. Lesser's critique that the Canadian proxy group includes both gas and electric utilities and consequently is neither comparable to FEI or FBC,[42] Mr. Coyne explained that he presented a Canadian proxy group to address any concerns that may arise regarding the comparability of US proxy groups in establishing the allowed ROE for FEI and FBC.[43] Mr. Coyne submits that his US proxy groups address concerns regarding the comparability of these companies to FEI and FBC respectively, from an investment perspective because:[44]

1) The US gas proxy group is comprised of companies that derive 91 percent of each company's net operating income from regulated activities, 99 percent of operating income and 98 percent of revenues from gas utility operations, and dedicate 97 percent of assets to regulated gas utility service; and

[37] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Exhibit JMC-FBC-3, pp. 1–2.
[38] Exhibit B1-8-1, Appendix C, Figure 57, p. 133.
[39] Ibid., Appendix D, pdf p. 576.
[40] Ibid., Appendix C, p. 138.
[41] Exhibit B1-8-1, Appendix C, p. 55.
[42] Exhibit A2-20, BCUC IR 1.3.
[43] Exhibit B1-21, Part 2, p. 9.
[44] Exhibit B1-8-1, Appendix C, p. 55.

2) The US electric proxy group is comprised of companies that derive 95 percent of each company's net operating income from regulated activities, 97 percent of both operating income and revenues from electric utility operations and dedicate almost 97 percent of assets to regulated electric utility service.

In response to an IR asking Dr. Lesser what weight he would place on the Canadian versus US proxy groups, he stated that a better statistical approach would be to combine the Canadian and US companies into a joint North American proxy group for gas and electric utilities, respectively.

Dr. Lesser explained that this approach is reasonable because the countries' economies are highly integrated and capital markets are international. Dr. Lesser also suggested that one could evaluate differences between the allowed ROE values calculated for the Canadian and US companies. As an example, Dr. Lesser explained that if the four Canadian electric companies all had much lower allowed ROEs than the US companies, the BCUC could take that into consideration when setting the ROE for FEI and FBC.[45]

At the oral hearing, Mr. Coyne noted his agreement with Dr. Lesser's recommendation to use a North American proxy group for electric and gas utilities. Mr. Coyne also noted, one would have to "accept a little bit less Canadian representation" in forming a North American proxy group and explained that it is challenging to find a Canadian company that would pass the same screening criteria that he applied to the US companies.
With respect to a North American gas proxy group, Mr. Coyne believes that, of the Canadian companies, only AltaGas Ltd. would pass the screening criteria. (Enbridge Inc. would not pass due its low proportion of earnings from natural gas operations and similarly, Canadian Utilities Limited would not pass due to an approximate equal focus on electric and gas operations). With respect to a North American electric proxy group, Mr. Coyne expects three to four Canadian companies would pass the screening criteria. [46]

FortisBC acknowledges that Mr. Coyne developed his initial recommendation based on the results of his US proxy groups, consistent with the BCUC's 2016 Decision.[47] However, the evidence in this proceeding suggests that it would be appropriate for the BCUC to give primary weight to results based on Mr. Coyne's North American gas and electric proxy groups, in line with both experts' evidence, who agree that the extent of economic and market integration in North America justifies the use of North America-wide proxy groups to estimate the authorized ROE for FEI and FBC.[48]

Based on Mr. Coyne's explanation, FortisBC states that since only one Canadian gas company and three Canadian electric companies pass his screening criteria, there are substantial similarities in the composition of the US proxy groups and the North American proxy groups.[49] FortisBC also notes that Mr. Coyne testified that he has been advocating for using a North American proxy group approach for many years and would embrace a decision by the BCUC to adopt this approach in this proceeding.

FortisBC states that Dr. Lesser is in full agreement with Mr. Coyne on the extent of integration of the North American economy and capital markets and had advocated for the use of integrated North American gas and

[45] Exhibit A2-20, BCUC IR 1.3.
[46] Transcript Volume 3, p. 336 Line 21 to p. 338 Line 8.
[47] FBC Application for its Common Equity Component and Return on Equity for 2016 [FEI 2016 Cost of capital (COC)], Order G-129-16 and Decision dated August 10, 2016 (2016 Decision).
[48] FortisBC Final Argument, pp. 139–140.
[49] Ibid., pp. 140–141.

electric proxy groups. Dr. Lesser explains that "*per se* geographical constraints on the location of proxy group companies may eliminate comparable firms." Dr. Lesser observes that the Federal Energy Regulatory Commission (FERC) now allows for Canadian companies to be included in proxy groups for setting ROEs for pipelines and transmission utilities, given the level of integration and the similarity in how they are regulated.[50]

Positions of Parties

ICG

ICG does not challenge the proxy group companies of Concentric.[51] ICG agrees with FEI and FBC's submissions that the BCUC should place the greatest weight on the North American proxy groups.[52]

BCOAPO

Given the agreement of both Dr. Lesser and Mr. Coyne that the preferred approach is to use the North American proxy groups for gas and electric utilities, BCOAPO agrees with FortisBC's submission that "the BCUC should place the greatest weight on the North American proxy group results in light of the expert evidence." However, BCOAPO points to statements by Mr. Coyne and FortisBC, where both parties indicated that only three out of four Canadian electric utilities and only one out of three Canadian gas utilities would pass the screening criteria to be included in the appropriate North American proxy groups. Therefore, BCOAPO submits that the results for the North American proxy groups will need to be revised.[53]

As part of its final argument, BCOAPO has recalculated the ROE from the Multi-Stage DCF model and CAPM for: 1) a revised North American gas utility proxy group by removing Enbridge Inc. and Canadian Utilities Limited, leaving just AltaGas Ltd. as a Canadian gas utility in the new North American gas proxy group and 2) a revised North American electric utility proxy group by removing only Canadian Utilities Limited and leaving Algonquin Power and Utilities Corp., Emera Inc., and Hydro One Ltd. as the three Canadian electric utilities in the new North American electric proxy group.[54]

The CEC

The CEC submits that the experts' agreement on the proxy groups and on the North American integration of the two economies and capital markets is useful to the BCUC. However, the CEC does not agree that the integration leads automatically to the exclusion of US proxy group data and results by replacement with a North American proxy group. There are significant differences in the data which the CEC submits should be considered and given substantial weighting.[55] Thus, the CEC recommends that the BCUC give substantial weighting to the Canadian utilities, US utilities, and North American utilities proxy groups, and then average the results of each of these proxy groups.[56]

[50] FortisBC Final Argument, pp. 142–143.
[51] ICG Final Argument, p. 8.
[52] Ibid., p. 10.
[53] BCOAPO Final Argument, pp. 11–12.
[54] Ibid., pp. 43–44.
[55] The CEC Final Argument, p. 39.
[56] Ibid., p. 42.

RCIA

RCIA opposes the inclusion of US market data in ROE calculations for two reasons. First, RCIA submits that "the Canadian MRP should only be measured against the Canadian proxy group, as being country (and market) specific." And second, if the BCUC were to accept US data, there is no evidence to support an equal weighting of Canadian and US data in ascertaining an appropriate Canadian ROE.[57]

FortisBC Reply Argument

FortisBC points out that ICG has used internally inconsistent reasoning to reach its low recommended ROE. On the one hand, ICG agrees with the experts that the BCUC should give the greatest weight to the North American proxy group when determining ROE. FortisBC surmises that ICG's position is no doubt influenced by the fact that this tends to reduce FBC's ROE significantly relative to using the Canadian proxy group. On the other hand, ICG advocates for only using the Canadian utilities when determining the common equity ratio, while giving no weight to the same US proxy companies that ICG advocates using for the ROE calculations included in the North American proxy group.[58]

FortisBC submits that BCOAPO's exclusions of two companies from the North American gas and/or electric proxy groups are unwarranted. Even though Mr. Coyne has stated that he would probably have had to exclude Enbridge Inc. and Canadian Utilities Limited from his North American proxy groups if his screens were rigidly applied to Canadian companies, FortisBC points out that he refrained from doing so, as it would have undermined the value of using a North American proxy group with too few comparable Canadian utility companies. As noted by Dr. Lesser, there is a trade-off between larger proxy groups providing more statistically valid results, while some firms become less "comparable" to the regulated firm under review. In conclusion, FortisBC submits that Enbridge Inc. and Canadian Utilities Limited should remain a part of the North American proxy groups.[59]

FortisBC submits that the CEC's suggestion to average results from all proxy groups is unnecessary. Citing the experts' agreement on the appropriateness of using North American proxy groups, FortisBC submits that this approach is more appropriate than averaging the results of the Canadian, US and North American proxy groups. FortisBC points to the experts' agreement on Mr. Coyne's screening criteria for the North American and US proxy groups, while both experts noted the limited size and composition of the Canadian proxy group.[60]

FortisBC submits that RCIA's opposition to US data is inconsistent with the consensus expert evidence and regulatory practice. FortisBC notes that RCIA stands as the only intervener not to acknowledge the need to rely on US data. FortisBC submits that RCIA's position that Mr. Coyne has used assumptions that "baselessly incorporate … non-Canadian data, which in turn raise the assumption values and subsequently the recommended ROEs" is without merit. Indeed, using the October 2022 data, FortisBC points out that relying on the Canadian proxy group tends to slightly increase the overall ROE.[61]

[57] RCIA Final Argument, p. 17.
[58] FortisBC Reply Argument, pp. 55–56.
[59] FortisBC Reply Argument, pp. 57–58.
[60] Ibid., p. 57.
[61] Ibid., p. 58.

FortisBC also submits that there is ample basis for using US data in ROE analysis: a) both experts agree it is appropriate and both favour North American proxy groups; b) the BCUC's 2016 Decision used the US proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities; c) other Canadian regulators have taken a similar approach; and d) the extent of integration has only increased over time.[62]

Finally, FortisBC observes that RCIA has chosen to rely on US data to estimate the risk-free rate when this has the effect of suppressing its ROE results.[63]

Panel Determination

We begin our analysis by noting that both Mr. Coyne and Dr. Lesser agree with the need to establish a proxy group of companies. In doing so, we are cognizant of the need to ensure that we are indeed comparing apples to apples, notwithstanding any jurisdictional and operational differences between the utility in question and its proposed peers**.**

Furthermore, the makeup of any proxy group inherently involves some degree of professional judgment and discretion. Unfortunately, there are no reasonable comparators to FEI and FBC in BC. This is because FEI is the single largest natural gas distributor in the Province (PNG is considerably smaller), and in respect of FBC, there are no other vertically integrated electric utilities that are of comparable size within BC. This requires us to look elsewhere in Canada for suitable proxies to FEI and FBC.

In an ideal world, there would be sufficient comparators to each of FEI and FBC in Canada to allow the BCUC to use only data pertaining to Canadian counterparts as a starting point. However, the reality is to the contrary. As Mr. Coyne notes in his evidence, using a Canadian proxy group comprised of publicly traded, regulated Canadian electric and natural gas utility companies with comparable business and financial characteristics yields only six utilities (three electric and three gas). Due to this limited number, the only screening criterion that Mr. Coyne uses is an investment grade credit rating, which all six utilities possess. However, as Table 2 above shows, all three Canadian gas utilities (AltaGas Ltd., Canadian Utilities Limited and Enbridge Inc.) have total assets and annual revenues that range from double to 28x those of FEI, and one of them (Enbridge Inc.) only derives 16 percent of its total income from its regulated activities.

With respect to the three Canadian electric utilities, Table 3 shows that all three have total assets and annual revenues that range from 5x to 17x those of FBC. This suggests that these comparators may provide limited value for the purpose of determining an appropriate ROE for FEI and FBC and that our review of proxy groups therefore should not be confined to Canadian utilities alone.

With respect to using non-Canadian comparators, as Mr. Coyne correctly points out, several Canadian regulators, including the BCUC, have recognized the integrated nature of Canadian and US financial markets, that Canadian utilities are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly traded utilities. This has led to Canadian regulators adopting a pragmatic view of the use of US data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. We see no

[62] FortisBC Reply Argument, p. 58.
[63] Ibid., p. 59.

reason to deviate from the BCUC's previous determination regarding the reasonableness of using US market data and proxy groups and endorse the wisdom of continuing to do so in light of the small sample size of Canadian comparators notwithstanding any jurisdictional differences. We accept Mr. Coyne's evidence that the US gas and electric proxy groups are more comparable to FEI and FBC, respectively, in terms of business risk than the Canadian proxy group utilities, many of which have significant non-gas or non-electric operations and unregulated operations.

We agree as a matter of principle with the experts' suggestion to give primary weight to North American gas and electricity proxy groups. As Dr. Lesser notes, this change in practice is reflected in FERC now allowing for Canadian companies to be included in proxy groups for setting ROEs for US pipelines and transmission utilities because of the level of integration and the similarity in how they are regulated.[64]

We note that ICG and BCOAPO both agree with FortisBC's submission that "the BCUC should place the greatest weight on the North American proxy group results in light of the expert evidence." We reject the CEC's suggestion to give substantial and equal weighting to the Canadian utilities, US utilities, and North American utilities proxy groups, and to simply average the results of each of these proxy groups. For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.

However, with respect to the use of a North American gas proxy group, Mr. Coyne believes that only AltaGas Ltd. from the Canadian utilities would pass the six screening criteria he uses to create a group of essentially pure-play US gas and electric utilities with similar risk profiles to FEI and FBC respectively (Enbridge Inc. would not pass due its low portion of earnings from natural gas operations and similarly, Canadian Utilities Limited would not pass due to an approximate equal focus on electric and gas operations). With respect to a North American electric proxy group, Mr. Coyne expects three to four Canadian companies would pass the screening criteria. As a result, we find merit in BCOAPO's submission that Mr. Coyne's North American proxy groups will need to be revised to exclude the non-qualifying Canadian utilities.

Finally, we reject RCIA's submission for the BCUC to only use Canadian data for the Canadian proxy group because it is country and market specific. Instead, we agree with FortisBC that there is ample basis to include US data in our ROE analysis because:

- There are insufficient comparators to each of FEI and FBC in Canada to allow the BCUC to use only data pertaining to Canadian counterparts;
- Both experts agree that the inclusion of US data is appropriate and both favour the use of North American proxy groups;
- The BCUC's 2016 Decision used US proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities; and

[64] Exhibit A2-3, Lesser Report, pp. 14–15.

- Other Canadian regulators (and more recently FERC) have taken a similar approach; and the extent of North American financial and capital markets integration has only increased over time.

As for the weighting of the ROE results amongst the North American proxy group as between the Canadian utilities and the US utilities, we find that to be largely a matter of judgment that is within our discretion. However, we accept both Mr. Coyne and BCOAPO's caution about the need to remove the non-qualifying Canadian utilities from the proxy group based on Mr. Coyne's screening criteria and the resulting impact that this would have on our assessment of an appropriate ROE. In Sections 5.2.5 and 5.3.3 of this decision, we review the impact of the removal of the non-qualifying Canadian utilities from the North American proxy group on the resulting ROEs.

3.3 Use of Recent Data – October 2022

More than two years have elapsed since the BCUC initiated this proceeding on January 18, 2021. Mr. Coyne filed his original expert evidence with ROE results that were based on December 2021 data. As Mr. Coyne relied on the average of the CAPM and Multi-Stage DCF model to estimate the allowed ROE for FEI and FBC, he believes, based on the December 2021 data, that a reasonable estimate of FEI's required cost of equity is 10.1 percent and that of FBC is 10.0 percent, based on the US proxy groups. Not surprisingly, due to the passage of time, the Panel is concerned about the staleness of that data as a basis for establishing an ROE in 2023. Therefore, based on FortisBC's submission that both experts had indicated a preference for using the latest data, we directed Mr. Coyne to update his ROE analysis using market data inclusive of September 30, 2022.[65]

3.3.1 Mr. Coyne's Original ROE Results

Mr. Coyne's ROE results based on December 2021 data are shown in Table 4 below for the four models that he presented: CAPM, Constant Growth DCF, Multi-Stage DCF and Risk Premium Model.

Table 4: Summary of Results – December 2021[66, 67]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.68%	10.67%	11.05%	11.12%	10.8%
Constant Growth DCF	11.61%	10.39%	10.99%	9.57%	9.87%
Multi-Stage DCF	10.28%	9.53%	10.05%	8.82%	9.07%
Risk Premium		9.97%	9.97%	10.01%	10.1%
Average	**10.9%**	**10.3%**	**10.7%**	**10.0%**	**10.0%**
Avg CAPM and Multi-Stage DCF	**10.5%**	**10.1%**	**10.6%**	**10.0%**	**9.9%**

Table 4 shows that the average of all four models for the US gas proxy group is 10.3 percent, within the range of 9.53 percent to 10.67 percent, and the four-model average for the US electric proxy group is 10.0 percent,

[65] Order G-217-22, Appendix A, p. 11.

[66] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Figures 1 and 2, pp. 4–5.

[67] DCF results are based on 90-day average stock prices for proxy group companies. Results include a 50 bps for flotation costs and financial flexibility, except for U.S. risk premium results. The risk premium analysis was only conducted for the U.S. proxy groups; thus, there are no risk premium results the Canadian proxy group. The CAPM results do not include a leverage adjustment using the Hamada formula. The CAPM results do not include an adjustment for FBC's small size.

within the range of 8.82 percent and 11.12 percent. As Mr. Coyne relied on the average of the CAPM and Multi-Stage DCF model to estimate the allowed ROE for FEI and FBC, he opines, based on the December 2021 data, that a reasonable estimate of FEI's required cost of equity is 10.1 percent and that of FBC is 10.0 percent, based on the US proxy groups. As noted earlier, Mr. Coyne views that the US proxy group utilities are more comparable to FEI and FBC, respectively, in terms of business risk than those of the Canadian proxy group.

3.3.2 ROE Results from the September 2022 Update

Based on FortisBC's submission that both experts had indicated a preference for using the latest data, the BCUC directed Mr. Coyne to update his ROE analysis using market data inclusive of September 30, 2022.[68] Mr. Coyne's updated analysis using the September 30, 2022 data lowered the two-model average (Multi-Stage DCF and CAPM) from 10.1 percent (proposed) to 9.3 percent for FEI and from 10.0 percent (proposed) to 9.5 percent for FBC, based on the respective US proxy groups. Mr. Coyne describes those results as counter-intuitive in a macro environment characterized by sustained higher levels of inflation and substantially higher interest rates.[69] In his view, the December 2021 market data represents more normal market circumstances, before the war in Ukraine, aggressive interest rates' increases, sustained elevated levels of inflation, amongst other factors, significantly impacted capital markets in 2022. Accordingly, Mr. Coyne considers the December 2021 results to be more indicative of the actual cost of equity than data ending in September 2022 which are skewed by these market disruptions. Given the highly abnormal nature of 2022 and the transitory market circumstances, he is reluctant to change his ROE recommendations based solely on the September 2022 market data.[70]

The updates are shown below in Table 5.

Table 5: Summary of Results – September 2022 Update[71, 72]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.08%	9.87%	10.24%	10.43%	10.17%
Constant Growth DCF	11.74%	9.69%	10.72%	9.66%	9.92%
Multi-Stage DCF	10.24%	8.81%	9.57%	8.64%	8.93%
Risk Premium		10.12%	10.12%	10.17%	10.17%
Average	**10.7%**	**9.6%**	**10.2%**	**9.7%**	**9.8%**
Avg CAPM and Multi-Stage DCF	**10.2%**	**9.3%**	**9.9%**	**9.5%**	**9.6%**

Mr. Coyne's updated analysis lowered the two-model average (Multi-Stage DCF and CAPM) from 10.1 percent (proposed) to 9.3 percent for FEI and from 10.0 percent (proposed) to 9.5 percent for FBC, based on the respective US proxy groups. Mr. Coyne describes those results as counter-intuitive in a macro environment characterized by sustained higher levels of inflation and substantially higher interest rates.[73] In Mr. Coyne's view, these market circumstances require an examination of the models and inputs used to estimate ROEs and the

[68] Order G-217-22, Appendix A, p. 11.
[69] Exhibit B1-8-1-2, pp. 2, 4.
[70] Exhibit B1-8-1-2, pp. 6–7.
[71] Information in the table has been compiled from Exhibit B1-8-1-2, Figures 1 and 3, pp. 2–3.
[72] See footnote 67.
[73] Exhibit B1-8-1-2, pp. 2, 4.

application of informed judgment. With respect to the CAPM, Mr. Coyne expresses the following concern related to the estimation of government bond yields (risk-free rate):

> The forecast interest rates used in the September 2022 analysis are well below current levels. This may be due to the Consensus Economics' forecast lagging the fast-moving market, or to an expectation that central bank actions will stall the economy and bring down interest rates in the future. This has a direct impact on the CAPM and Risk Premium models.

With respect to the DCF models, Mr. Coyne expresses the concern that utility stock prices had responded slowly to the down market in 2022 so the 90-day historic stock price averages used in the DCF models are not reflective of the market condition as of the end of September 2022.

Therefore, Mr. Coyne has replaced the forecast bond yields with the current bond yields (spot price) in the CAPM formula to examine the impact of this factor on the output of the CAPM (see Table 6, CAPM results). Also, Mr. Coyne has replaced the 90-trading day average utility stock prices with the current stock prices (spot price). The Multi-Stage DCF model results increase significantly across all proxy groups, and for the most part, surpasses the December 2021 results (see Table 6, Multi-Stage DCF results).

Table 6: Summary of Results – September 2022 Update – Spot Update[74, 75]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	**10.10%**	**10.33%**	**10.51%**	**10.88%**	**10.50%**
Constant Growth DCF	12.38%	10.04%	11.14%	10.17%	10.49%
Multi-Stage DCF	**11.06%**	**9.21%**	**10.07%**	**9.23%**	**9.61%**
Risk Premium		10.22%	10.22%	10.28%	10.28%
Average	11.2%	10.0%	10.6%	10.1%	10.2%
Avg CAPM and Multi-Stage DCF	10.6%	9.8%	10.3%	10.1%	10.1%

Mr. Coyne notes, when incorporating these input changes into the CAPM and DCF model, the model results shift back towards those estimated in December 2021. In his view, the December 2021 market data represents more normal market circumstances, before the War in Ukraine, aggressive interest rates' increases, sustained elevated levels of inflation, amongst other factors, significantly impacted capital markets in 2022. While Mr. Coyne would not rely on spot market data to estimate the CAPM and Multi-Stage DCF model, he considers the spot market results more indicative of the actual cost of equity than data ending in September 2022 skewed by these market disruptions. The highly abnormal nature of 2022 and the transitory market circumstances explain Mr. Coyne's reluctance to change his ROE recommendations based solely on the September 2022 market data.[76]

3.3.3 ROE Results from the October 2022 Update

At the oral hearing, Mr. Coyne offered to further update his ROE model results to the end of October 2022. His updates were based on both the 90-day and 30-day average stock prices for the DCF model and are shown

[74] Information in the table has been compiled from Exhibit B1-8-1-2, Figures 3 and 4, p. 6.

[75] See footnote 67.

[76] Exhibit B1-8-1-2, pp. 6–7.

below, in Table 7 and Table 8, respectively. That analysis shows an increase in ROE[77] from the September 2022 data to an ROE of 9.5 percent (90-day) and 9.8 percent (30-day),) respectively for FEI, and 9.6 percent (90-day) and 10.0 percent (30-day) for FBC, based on the October 2022 data which more closely approximate the results using the December 2021 data.[78]

A more in-depth discussion on the appropriate averaging period to calculate the dividend yield in the Multi-Stage DCF model can be found in Section 5.3.1 below.

Table 7: Summary of Results – October 2022 Update (Scenario A.2, 90-day)[79]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.12%	9.96%	10.30%	10.51%	10.24%
Constant Growth DCF	11.98%	9.81%	10.95%	9.67%	10.09%
Multi-Stage DCF	10.46%	8.94%	9.72%	8.74%	9.11%
Risk Premium		10.12%	10.12%	10.16%	10.16%
Average	**10.9%**	**9.7%**	**10.3%**	**9.8%**	**9.9%**
Avg CAPM and Multi-Stage DCF	**10.3%**	**9.5%**	**10.0%**	**9.6%**	**9.7%**

Table 8: Summary of Results – October 2022 Update (Scenario A.3, 30-day)[80]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.07%	10.27%	10.46%	10.82%	10.45%
Constant Growth DCF	12.35%	10.07%	11.22%	9.98%	10.44%
Multi-Stage DCF	10.93%	9.24%	10.03%	9.10%	9.52%
Risk Premium		10.12%	10.12%	10.16%	10.16%
Average	**11.1%**	**9.9%**	**10.5%**	**10.0%**	**10.1%**
Avg CAPM and Multi-Stage DCF	**10.5%**	**9.8%**	**10.2%**	**10.0%**	**10.0%**

During the oral hearing, Mr. Coyne discussed the October 2022 data beginning to reflect more normal conditions with alignment around expectations for utility stock prices to decrease and dividend yield to start increasing, "but yet not fully in sync with where bond yields were going."[81]

In its final argument, FortisBC submits that the evidence supports a finding that the required cost of equity for FEI and FBC is, respectively, 10.1 percent (on 45 percent common equity) and 10.0 percent (on 40 percent common equity). FortisBC states that these proposed ROEs are based on the recommendations of Mr. Coyne, who is the only expert in this proceeding who conducted a full cost of capital analysis.[82] FortisBC also notes the

[77] Consisting of the average of CAPM and Multi-Stage DCF ROEs.

[78] Transcript Volume 4, p. 574, Lines 11–12.

[79] Information in the table has been compiled from Exhibit B1-50, Figures 3 and 4, p. 6.

[80] Information in the table has been compiled from Exhibit B1-50, Figures 5 and 6, p. 7.

[81] Transcript Volume 4, p. 574, Lines 11–12.

[82] FortisBC Final Argument, p. 121.

experts' alignment on key aspects of the analysis, including the reasonableness of relying primarily on the most recent October 2022 data.[83]

FortisBC states that, although the BCUC should be giving the most weight to October 2022 data, the BCUC can take additional comfort from the fact that there is reasonable alignment between the December 2021 and October 2022 ROE results. Mr. Coyne regards the December 2021 results as more reflective of "more normal market circumstances" than the September 2022 results filed prior to the oral hearing. The October 2022 results show the markets emerging from extraordinary market conditions over the summer, which have suppressed the September 2022 Update model results.[84]

Positions of Parties

ICG

ICG agrees that the BCUC should adopt the use of the October 2022 data. However, ICG submits that the BCUC should not conclude that the October 2022 results are potentially understating the investor-required return, as this would be inconsistent with the Efficient Market Hypothesis[85] and investor expectations would be substituted with those of the BCUC.[86]

BCOAPO

BCOAPO points to the experts' agreement to use the most recent market data to justify BCOAPO's use of Mr. Coyne's October 2022 results for its own ROE calculations and recommendations.

The CEC

The CEC submits that the BCUC should give weight to Mr. Coyne's ROE calculations using October 2022 data in making its informed judgement about how capital markets are impacting ROE models and what is a fair return, as these results appear to be better and sufficiently recent. The CEC further submits that FortisBC's observation that there is reasonable alignment between results based on the October 2022 data and the December 2021 data is important and helps validate the use of the October 2022 data on which the BCUC should rely.[87]

The CEC notes the sensitivity of ROE modelling to movements in bond yields and prices in stock markets to be out of sync for extended periods of time, and that use of data that may not be in sync could distort the results significantly. The CEC submits that the experts' attention to this and the selection of preferred data points are important factors for the BCUC to be relying on and finding appropriate as the basis for its ROE decisions.[88]

[83] FortisBC Final Argument, p. 122.
[84] Ibid., p. 146.
[85] Efficient Market Hypothesis is described in Section 4.0.
[86] ICG Final Argument, p. 11.
[87] The CEC Final Argument, p. 38, 43.
[88] Ibid., p. 44.

RCIA

RCIA makes no submission *per se* on which data to use; however, RCIA has relied on the December 2021 data to make its ROE recommendations.

FortisBC Reply Argument

FortisBC states that, while RCIA does not explain why it has disregarded the October 2022 data, its reliance on December 2021 data is a significant determinant of its low ROE recommendations. Even if the BCUC were to accept each of RCIA's methodological changes to Mr. Coyne's CAPM, which FortisBC submits the BCUC should not do, simply updating RCIA's recommended changes with October 2022 data produces an ROE of 9.43 percent, which is significantly higher than RCIA's proposed 8.00 percent to 8.75 percent. And averaging that result with the Canadian Multi-Stage DCF result of 10.46 percent would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent (on 45 percent common equity) for FEI and 10.0 percent (on 40 percent common equity) for FBC.[89]

Panel Discussion

The Panel is persuaded by Mr. Coyne's evidence, as the only expert in the proceeding who has prepared a full cost of capital analysis, that the October 2022 data are beginning to reflect more normal conditions with alignment around expectations for utility stock prices to decrease and dividend yield to start increasing, albeit "yet not fully in sync with where bond yields were going."

The Panel accepts that overall, the October 2022 results show the markets emerging from extraordinary market conditions over the summer of 2022, which may have artificially suppressed Mr. Coyne's September 2022 Update model results due to market volatility.[90]

The Panel is persuaded about the reasonableness of using the October 2022 market data, being the most recent publicly available data, to inform us in the establishment of an appropriate cost of capital. In that regard, we note the two experts' alignment on key aspects of the analysis, including the reasonableness of relying primarily on the most recent October 2022 data.[91] We note that all the interveners who provided submissions on the timing of the data support the use of the October 2022 data.

While both FortisBC and the CEC point to the fact there is reasonable alignment between the results based on the October 2022 data and those based on the December 2021 data as an important factor that helps to validate the use of the October 2022 data,[92] we do not consider that to be persuasive. Rather, we find that the passage of time has rendered the December 2021 data stale as a basis for establishing an appropriate cost of capital in 2023, and that, absent special circumstances, reliance on the most current data provides a more sound and principled basis for setting the cost of capital.

[89] FortisBC Reply Argument, pp. 50–51.
[90] FortisBC Final Argument, p. 146.
[91] Ibid., p. 122.
[92] The CEC Final Argument, p. 38, 43.

4.0 BUSINESS RISK AND CREDIT RATINGS

FortisBC describes business risk analysis as an important factor in an investor's decision-making process and states, from the investors' perspective, any factor that may negatively impact a utility's current and future cash flows should be considered a risk. [93] FortisBC also notes that business risk and financial risk come into play in the determination of a fair return through a comparison with other utilities such as Mr. Coyne's analysis as part of the Application.[94]

FortisBC explains that both business risk and financial risk impact capital structure, as the BCUC has historically given substantial weight to business risk, and more particularly, changes in business risk, to justify its capital structure determinations for both FEI and FBC.[95] As such, FEI and FBC demonstrate how the changes in each utility's business risks justify FEI and FBC's proposed common equity ratios.

FortisBC also addresses financial risk in its submissions and the importance of maintaining FEI's and FBC's credit ratings, and provides evidence as to why weak financial metrics can result in negative rating action.[96] As Mr. Coyne explains, a more highly leveraged company requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders.[97] FortisBC explains, in addition to business risk, financial risk and credit ratings determine the utilities' ability to attract capital and maintain each utility's financial strength.[98]

Dr. Lesser describes under the semi-strong form of the Efficient Market Hypothesis that prices paid for different types of securities – both debt and equity – must reflect all relevant publicly available information available to investors. This also requires that all perceived risks are taken into account by investors. As part of the decision-making process, Dr. Lesser states, investors as a class must be aware of or have efficient access to all publicly available information, including bond ratings and rating agency reports, equity ratings and discussions by ratings agency reports, and the various methodologies used to determine the cost of debt and equity as contained in the finance literature.[99]

Dr. Lesser and Mr. Coyne both agree that if perceived risks are commonly believed, those risks will be relevant to the calculation of expected returns. Mr. Coyne also notes that looking at the last five years would show real risks that have come to fruition.[100] Mr. Coyne states that overall and taken together, business risk and financial risk are the primary elements of risk that investors consider when establishing their return requirements.[101]

Given the impact of business risk on utilities' expected return, the Panel will review this from the perspective of the shareholder, as it is an important consideration for investors when making their investment decisions. This is

[93] Exhibit B1-8-1, p. 2.
[94] Exhibit B-1, p. 2.
[95] Exhibit B1-8, p. 5.
[96] Ibid.
[97] Exhibit B1-8-1, Appendix C, p. 73.
[98] Exhibit B1-8, p. 25.
[99] Oral Hearing Transcript, Volume 4, p. 474, Exhibit B1-40, p. 15.
[100] Oral Hearing Transcript, Volume 4, p. 475, Volume 5B, p. 914.
[101] Exhibit B1-8-1, Appendix C, p. 73.

consistent with the BCUC's view of risk in the 2013 Decision,[102] as the probability that future cash flows will not be realized or will be variable, resulting in a failure to meet investor expectations.[103]

Part of this Panel's review includes investors' consideration of credit ratings and whether this has an impact on the Panel's overall determination of ROE and capital structure. The Panel notes that, while this section focuses on business risk, the related financial risk is addressed in Section 6.0 where the Panel makes its overall determinations on ROE and capital structure.

Therefore in this section, the Panel will focus on the following issues:

1. The importance of credit ratings and whether they ought to be an input in the overall determination on ROE and capital structure; and
2. Whether business risk has changed from an investor and shareholder's perspective for FEI and FBC.

4.1 Credit Ratings

Overview

Credit ratings take into account business and financial risks and can provide a broad measure of investment risk for investors.[104]

In determining whether specific credit ratings are to be maintained, credit rating agencies may take into account such factors as evolving concerns regarding energy transition impacts, as well as the utility's financial leverage. Credit ratings can affect a utility's access to debt, as well as its ability to earn a fair return, which may be supported (or countered) by sudden changes in credit ratings. For example, a significant downgrade in credit rating could impair the financial integrity of the utility by reducing its ability to maintain credit and access capital on reasonable terms.[105] Specifically, credit ratings can drive the cost of debt, whereby a higher credit rating is associated with a lower cost of debt and vice versa.[106]

In the 2013 Decision, the BCUC noted there were advantages to establishing an ROE and capital structure which would allow for existing investment grade rating to be maintained but also noted this may result in a capital structure or ROE that is suboptimal in the circumstances. The BCUC in the 2013 GCOC proceeding, supported the maintenance of an investment grade credit rating but only to the extent that it could be maintained without going beyond what is required by the Fair Return Standard.[107] Therefore, The Panel in this proceeding needs to determine the importance it should place on the maintenance of a credit rating when establishing the utility's capital structure and ROE.

Mr. Coyne has included credit ratings as part of his screening test for proxy groups in this proceeding, requiring an investment grade credit rating to ensure that the proxy group companies, like FEI and FBC, are in "sound

[102] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013 (2013 Decision).
[103] 2013 Decision, p. 24.
[104] Exhibit B1-8-1, Appendix C, p. 43.
[105] 2013 Decision, p. 48.
[106] Exhibit B1-13, RCIA IR 2.2.1 and 4.1.2.
[107] 2013 Decision, pp. 48–50.

financial condition."[108] Credit analysts focus on the potential for default on debt obligations and rate the financial strength of the companies they cover, with BBB from S&P or Baa from Moody's being investment grade.[109] Mr. Coyne specifically screened "credit ratings of at least BBB+ from S&P or Baa1 from Moody's."[110] He notes that credit ratings are commonly used as screens in cost of capital analysis in regulatory proceedings; however, they are "exclusively focused on the risks for debt investors, but do not account for the risks for equity investors."[111]

FEI

FEI is rated by Moody's as of December 2022 and DBRS Morningstar (DBRS) as of March 2021, at A3 (stable)[112] and A (stable),[113] respectively. FortisBC explains that FEI's A level rating ensures that the utility is able to access capital markets on reasonable terms and pricing in most market conditions. FortisBC states, FEI's access to debt capital markets would be more restricted if FEI were downgraded from its current A-level rating to the BBB category rating. If FEI is downgraded to a BBB-category rating, coupled with the fact that FEI is facing increasing scrutiny from investors, credit rating agencies and financial institutions around environmental, social and governance (ESG)-related risks may make it more difficult for FEI to access debt capital markets, especially in times of significant volatility.[114]

Moody's provides the following overview of FEI's profile in its December 2022 Report:[115]

> FortisBC Energy Inc.'s (FEI) credit profile is driven by its low business risk gas transmission and distribution assets that operate in the credit supportive regulatory environment of British Columbia and its monopoly position in its service territory. The company has a long track record of earning its allowed return on equity and its cash flow continues to be highly predictable. These strengths are offset by the company's weak financial metrics that we forecast will be in the range of 11-13% CFO pre-W/C to debt. These financial metrics are primarily a product of a low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates.
>
> The stable outlook for FEI is based on our expectation of a continuing supportive regulatory environment and consistent, albeit weak, financial metrics that provide limited cushion at the current rating level.[116]

Moody's has also begun to incorporate ESG-related criteria into its credit rating analyses, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change.[117]

[108] Exhibit B1-8-1, Appendix C, p. 43.
[109] Ibid., Appendix C, p. 117.
[110] Ibid., Appendix C, p. 40.
[111] Exhibit B1-8-1, Appendix C, p. 43.
[112] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, p. 1.
[113] Exhibit B1-8-1, Appendix D – 2 Credit Rating Reports, FortisBC Energy Inc. DBRS – 2021 Credit Rating Report.
[114] Exhibit B1-9, BCUC IR 6.3.
[115] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, p. 1.
[116] Ibid., p. 2.
[117] Exhibit B1-8-1, Appendix C, p. 80.

Moody's provides an ESG impact score for FEI in its December 2022 Report of moderately negative indicating that FEI's ESG attributes have an overall limited impact on the current rating, with potential for future negative impact over time. Moody's states, the scores reflect high environmental risks, moderate social risks and low governance risks with greatest area of concern being "Environmental."[118] Moody's states that FEI's high environmental risk reflects its elevated exposure to carbon transition risk given BC's legislated commitments to reduce greenhouse gas emissions by 40 percent by 2030 and 80 percent by 2050 and that all of the company's network operations are gas.[119]

DBRS confirms FEI's current credit ratings and notes all trends are stable according to its March 2021 credit report on FEI.[120] FortisBC notes that the confirmations reflect FEI's strong financial and business risk profile and its financial profile remained solid in the last 12 months. Further, DBRS notes that 2021 credit metrics "remained relatively stable and consistent" with its required levels to support the current ratings and "FEI's liquidity was viewed as solid, reflecting stable cash flows, sizable credit facility availability, and the next long-term debt maturity is in 2026."[121]

In addition, DBRS acknowledges that the BCUC has initiated this GCOC proceeding, which will include a review of the deemed equity component of total capital structure and allowed ROE for FEI and other regulated utilities and notes that any material changes in the allowed ROE or deemed equity may affect FEI's credit profile.[122]

Positions of Parties

FortisBC submits that maintaining FEI's existing A-category rating is important for accessing capital on reasonable terms in variable market conditions. Furthermore, an increase in FEI's common equity ratio is required to support its existing credit rating, which is under strain from weak financial metrics, increased weighting for ESG criteria, and potential changes in interest deductibility rules.[123]

Interveners offer differing views on FEI's credit ratings.

The CEC submits that the objective of maintaining the FEI A credit rating is useful and appropriate for FEI customers. Further, the CEC submits that evidence with respect to equity thickness and its impact on credit ratings, "combined with understanding the credit rating process and the consequences for FEI and FBC borrowing and the impacts on customers," leads the CEC to favour increasing the FEI equity thickness, increasing it to 40 percent, and not overreaching on the ROE increases. The CEC submits that "the impact on the credit rating process is more critical than perhaps additional small percentages on the ROE increases."[124] The CEC also notes, "nobody in that 2016 proceeding was using terms like "Energy Transition" or Environmental, Social and Governance (ESG) based investing"[125] and that "[t]here is increasing weight being given by investors to ESG issues."[126]

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[118] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, pp. 6–7.
[119] Ibid., p. 7.
[120] Exhibit B1-8-1, Appendix D, FEI DBRS Rating Report dated January 5, 2022, p. 1.
[121] Ibid., p. 2.
[122] Ibid., p. 1.
[123] FortisBC Final Argument, pp. 79–80.
[124] The CEC Final Argument, p. 47.
[125] FortisBC Final Argument, p. 24.
[126] The CEC Final Argument, p. 47.

In contrast, BCOAPO argues that the "financial circumstances are not as "dire" as portrayed"[127] and notes that "FortisBC has confirmed that the impact due to changes in regulatory assets could be either up or down in a given year and that the credit rating agencies fully understand this."[128] BCOAPO concludes that much of the business and financial risk associated with the Energy Transition/ESG is already captured by the financial models (e.g. the increased Beta in the CAPM) used to determine the recommended ROE. As a result of the relevant considerations, BCOAPO's recommends an increase in FEI's equity ratio in the range of 40 percent to 42 percent.[129]

In response, FortisBC states that "[t]he primary consideration regarding ESG is not FEI's position relative to other gas companies, but rather the fact that it will be more challenging for FEI to maintain its current rating than it had been in the past given the increasing weight that investors and rating agencies are giving to ESG considerations."[130] FortisBC argues that "FEI needs a stronger balance sheet to counteract this downward pressure."[131] Furthermore, with respect to raising capital, FortisBC explains that FEI's ability has been "facilitated by its existing A level credit rating" and that "[m]aintaining an A level credit rating ensures FEI is able to access capital markets on reasonable terms and pricing in most market conditions."[132]

FBC

FBC is rated by Moody's as of December 2022 and DBRS as of March 2021 at Baa1 (stable)[133] and A (low) (stable),[134] respectively. FortisBC explains that FBC has limited access to the market compared to a larger A-level rated utility, such as FEI, due to FBC's smaller size, its credit rating, and restrictive trust indentures that are sensitive to changes in the cost of borrowing. Therefore, FortisBC states, maintaining FBC's credit rating is critical. If FBC's credit rating is downgraded, its access to capital markets would be further diminished and the pricing and terms for the financing of the debt component of its capital expenditures and operations would become less favourable.[135]

Moody's provides the following overview of FBC's profile in its December 2022 Report:[136]

> FortisBC Inc.'s (FBC) credit profile is driven by its credit supportive regulatory environment and the monopoly position of its stable vertically integrated utility assets. Like affiliate utility FortisBC Energy, Inc. (FEI), the company has a track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, that we forecast will be in the range of 8-10% CFO pre-W/C to debt. These financial metrics are primarily the product of a low allowed equity ratio, a low return on equity, depreciation rates as well as a significant capitalized lease adjustment.

[127] BCOAPO Final Argument, p. 61.
[128] Ibid., p. 61–62.
[129] BCOAPO Final Argument, p. 65.
[130] FortisBC Reply Argument, p. 29.
[131] Ibid., p. 29.
[132] Ibid.
[133] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 1.
[134] Exhibit B1-8-1, Appendix D – 2 Credit Rating Reports, FortisBC Inc. DBRS – 2021 Credit Rating Report.
[135] Exhibit B1-9, BCUC IR 26.1.
[136] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 1.

As with FEI, Moody's has begun to include a ESG score for FBC. As of Moody's December 2022 Report, FBC is rated neutral-to-low because its ESG attributes have a limited impact on the current credit rating. Moody's states, FBC's score incorporates moderately negative environmental and social risks and low-to-neutral governance risks.[137]

Moody's does not have a predominant concern about FBC's ESG considerations but states, FBC's moderately negative environmental risk is driven primarily by its exposure to physical climate risks.[138] Moody's notes that FBC's exposure to social risks is moderately negative, as there is a fundamental risk associated with regulated utilities that demographic and social trends could include social pressure of public concerns around affordability, utility reputational risks or environmental concerns. These pressures could result in adverse political intervention or regulatory challenges.[139]

DBRS states in its March 2021 credit report that the FBC rating reflects FBC's strong financial risk profile and DBRS 's view that the regulatory framework in BC is supportive and stable for FBC's business risk profile over the medium term.[140]

DBRS notes that any material changes in the allowed ROE or deemed equity as a result of GCOC proceedings may affect FBC's credit profile. FBC's credit metrics in 2020 remained solidly supportive of the current ratings and the cash flow-to-debt and interest coverage ratios were consistent with the 2019 levels. DBRS expects FBC's credit metrics to remain stable over the near to medium term. If FBC's credit metrics weaken significantly from the current level on a sustained basis, it could negatively affect the company's ratings. However, DBRS considers this scenario unlikely.[141]

Positions of Parties

FortisBC submits that FBC's financial metrics are very weak for its current rating and are consistent with a non-investment grade credit (i.e. Moody's Ba rating category). FortisBC states, FBC's credit rating is at risk of a downgrade if its financial metrics deteriorate further, which would have significant ramifications for FBC's ability to issue debt on reasonable terms and price. FortisBC submits that key determinants of FBC's weak financial metrics are the low allowed equity component of its capital structure and low return on equity.[142]

Interveners offer differing views on FBC's credit ratings.

The CEC accepts the need for FBC to maintain its credit rating and submits that the proposal to maintain its equity thickness at 40 percent is reasonable. The CEC acknowledges that a downgrade of FBC's credit rating would diminish its access to capital markets and to favourable prices and terms of financing for its debt issuances, as FBC has smaller and less frequent requirements to raise capital, which causes it to not be in the bond index. These issues contribute to weaker demand and lower liquidity for FBC bonds.[143]

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[137] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 6.
[138] Ibid., p. 7.
[139] Ibid.
[140] Exhibit B1-8-1, Appendix D, DBRS FBC Rating Report dated March 15, 2021, p. 1.
[141] Ibid., p. 2.
[142] FortisBC Final Argument, p. 116.
[143] The CEC Final Argument, pp. 49–50.

BCOAPO states that it does not accept that there is any evidence that FBC's business risk or its financial risk is as significant as FBC and Mr. Coyne would have parties believe. However, BCOAPO submits that due to FBC's weak credit rating, it accepts Mr. Coyne and FBC's recommendation that the deemed equity ratio be set at 40 percent.[144] BCOAPO states that in FBC's case, there is little discussion regarding the implications of ESG considerations on the company's access to capital and Mr. Coyne's evidence indicates that FBC would fall at the lower end of the carbon intensity spectrum. As a result, BCOAPO expects "that this characterization will continue to exert a positive, or at worst, a neutral influence in terms of FBC's access to capital, negating any concerns from an ESG perspective."[145]

ICG states that Mr. Coyne opines that FBC's core credit ratios provide little cushion for FBC to maintain its current long-term issuer rating of Baa1 from Moody's. However, ICG notes that the credit report filed as part of FortisBC's Undertaking No. 3 confirmed all FBC credit ratings and concluded that the credit metrics in 2021 remained solidly supportive of the current ratings. ICG states that the report acknowledges if FBC's credit metrics weaken on a sustained basis, it could negatively affect the company's ratings, but notes that this scenario is unlikely and FBC's financial profile remained stable and strong in 2021. ICG submits that this contradicts submissions in FortisBC's Final Argument where it states that FBC's financial metrics are now weak to the point of being generally inconsistent with its current rating.[146]

In response, FortisBC states, the Fair Return Standard requires more than meeting the lowest common denominator; a utility should be able to attract capital on reasonable terms, and financial integrity is also a relevant consideration. FortisBC submits that FBC is facing risk of a downgrade. FortisBC states that most of FBC's financial metrics are consistent with a non-investment grade credit rating, which if applied to FBC, would be a significantly pervasive and profoundly negative development for the utility and customers, as investors generally do not invest in non-investment grade entities, and raising capital would become extremely difficult for FBC.[147]

Panel Discussion

In determining an appropriate ROE and capital structure for FEI and FBC, the Panel considers that it should be careful not to adversely affect each utility's current credit ratings because investors view credit ratings as reflective of the credit rating agencies' assessment of their business and financial risks and hence, the riskiness of such investments.

The Panel is aware that both debt and equity investors, in particular institutional investors, rely on credit rating agencies' reports, which are readily available and updated regularly, to inform them about the wisdom of maintaining, reducing or increasing their respective investments. Furthermore, the Panel accepts FEI and FBC's submission that a lowering of credit agency ratings can raise concerns for potential investors about the utilities' cost of debt and access to the credit market at reasonable cost. Therefore, there are advantages to establishing an ROE and capital structure which will allow for the utilities' existing credit agency ratings to be maintained and

[144] BCOAPO Final Argument, p. 70.
[145] BCOAPO Final Argument, p. 68.
[146] ICG Final Argument, pp. 16–17.
[147] FortisBC Reply Argument, p. 39.

avoid eroding each utility's ability to access capital at reasonable cost.[148] Simply put, investors view credit ratings as reflective of the utilities' relative financial health and ability to access capital at a reasonable cost.

The BCUC must ensure that the entities it regulates maintain the ability to access capital at a reasonable cost to enable such entities to continue to finance company operations and make the necessary capital investments to maintain and upgrade company systems. Our goal is to have financially sound utilities operating in the province so as to avoid a worst case scenario in which a utility defaults because it is not able to access capital at a reasonable cost. We do not consider that allowing such a scenario to unfold is in the interest of the utility, ratepayers or the public. Accordingly, in establishing an appropriate ROE and capital structure for the utilities, we must strive to strike the right balance between debt and capital which does not result in a credit rating downgrade for the utility.

We observe that generally speaking, both FEI and FBC have relatively sound and stable credit ratings, notwithstanding concerns about increasing Energy Transition and ESG impacts in the case of FEI and weak financial metrics in the case of FBC as we discuss in the following two subsections. In setting the ROE and capital structure for each utility, we consider it prudent not to take any action that would directly or indirectly have an adverse impact on either FEI or FBC's current credit ratings, as that would drive up each utility's cost to access capital which in turn is likely to result in rate increases for FEI and FBC customers.

However, assuming the ROE remains the same and all else equal, as long as we do not decrease FEI or FBC's current equity component, we view the risk of a credit rating downgrade to be unlikely in the circumstances. Similarly, all else being equal, any increases in FEI or FBC's equity component that we may approve as a result of this proceeding are likely to improve the financial health and viability of the utilities to the mutual benefit of the utilities' shareholders and ratepayers.

In this case, FEI and FBC's current credit ratings are satisfactory for maintaining the financial integrity of the respective utility and do not require an improvement for each utility to be able to continue to attract capital on reasonable terms. Therefore, the Panel does not view the utilities' credit ratings *per se*, unlike business risks, as a relevant input that would warrant a higher or lower ROE or change in capital structure in these circumstances.

4.2 FEI Business Risk

FEI's business risk was last reviewed in the FEI 2016 Cost of Capital (FEI 2016 COC[149]) proceeding.[150] In its evidence here, FEI provides an overview of its business risks across nine categories: two of which it considers to be of similar risk-level since the FEI 2016 COC proceeding and the remaining seven of which it considers to be of higher risk. FEI used the same categories in the FEI 2016 COC proceeding, other than the Indigenous Rights and Engagement risk factor, that has now been promoted to its own risk category.[151] Additionally, some of the existing risk categories have new risk factors: energy supply renewable gas supply factor and operating attitudes towards fossil-fuel industry, municipal operating challenges, and cybersecurity. FEI notes, while all of the risk categories are important contributors to its overall business risk, political risk and regulatory risk have the

[148] 2013 Decision, p. 48.
[149] FBC Application for its Common Equity Component and Return on Equity for 2016 proceeding.
[150] Exhibit B1-8, p. 2.
[151] Exhibit B1-8-1, Appendix A, p. 1.

greatest potential to affect FEI's ability to earn its return on, and of, invested capital.[152] FEI summarizes its risk as follows:[153]

> The risk factor analysis demonstrates that FEI's overall business risk is significantly higher in comparison to the 2016 Proceeding for two reasons. First, most categories present higher risk since the 2016 Proceeding. Second, political and regulatory risk, which are both higher due in large measure to the Energy Transition, are the risk categories where changes presently have the greatest potential to affect FEI's ability to earn its return on, and of, invested capital.

Table 9 below provides a summary of this risk assessment.

Table 9: Summary of FEI's Business Risk[154]

Business Risk Category	Risk Factor	Change in Risk Since 2016
Business Profile		**Similar**
	Type and size of the utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Higher**
	Climate action goals and expectations	Higher
	Energy policies and legislation	Higher
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher
Energy Price		**Higher**
	Commodity price	Higher
	Commodity price volatility	Higher
	Price competitiveness and carbon tax	Higher
Demand/Market		**Higher**
	Perception of energy	Higher
	New technology and energy forms	Higher
	Net customer additions	Higher
	Changes in building type and capture rates	Similar
	Changes in end-use market share	Higher
	Changes in use per customer	Similar
Energy Supply		**Similar**
	Availability of supply	Similar
	Access to supply	Similar
	Renewable Gas supply	New (Higher)
Operating		**Higher**
	Aging infrastructure and time dependent threats	Similar
	Third party damages	Similar
	Attitudes towards fossil-fuel industry	New (Higher)
	Municipal operating challenges	New (Higher)
	Cybersecurity	New (Higher)
	Unexpected events	Higher
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

[152] Exhibit B1-8-1, Appendix A, p. 2

[153] FortisBC Final Argument, p. 32.

[154] Exhibit B1-8-1, Appendix A, pp. 2–3.

While energy transition is not included as its own risk category in FEI's risk assessment, it covers a broad spectrum of risks that are transforming gas utilities' risk profiles in North America,[155] and therefore is discussed before the other risk categories, as it has implications for many of the other categories.

The sections below review each of the business risk categories and the positions of parties. To provide a comprehensive discussion, the Panel addresses all submissions received pertaining to FEI before making its overall findings and determinations on changes in FEI's business risk since the FEI 2016 COC proceeding.

Energy Transition

FortisBC reports the increasing pace of the energy transition from fossil fuels to cleaner sources of energy through electrification of the economy, and increased recognition of the effect of this transition on natural gas utilities by utility analysts and investors, represent what Concentric refers to as a "transformation of long-term risk environment" for natural gas utilities across North America.[156] FortisBC explains that the term "Energy Transition" risk is a new umbrella term which covers that spectrum of risk.[157]

FortisBC states that this risk is apparent in the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap) which establishes a greenhouse gas reduction obligation for natural gas utilities to reduce emissions from energy delivered to the buildings and industrial sectors. The Roadmap is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for FEI's customer rates and throughput. FortisBC has characterized the policy developments associated with the Energy Transition as political risk, but also states that these developments impact other risk categories since the FEI 2016 COC proceeding such as Indigenous Rights and Engagement, demand/market, regulatory, operating, and economic conditions risks.[158]

Mr. Coyne notes that the Energy Transition creates stranded asset risk for FEI by introducing the possibility that significant portions of FEI's assets will cease being used and useful before being fully depreciated, which could impact growth prospects or profitability of FEI's operations.[159] Mr. Coyne also notes that although according to S&P, "[s]tranded costs have not up until now been an issue for gas local distribution companies," concerns about stranded assets have spiked recently, "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond."[160]

Dr. Lesser also considers Energy Transition risk to be primarily a regulatory/policy risk because companies are required to meet specific policy goals. The risks of meeting those goals can then result in secondary business and financial risks (e.g. cost-overruns associated with a new technology and stranded asset costs), depending on how regulators treat the companies' efforts to meet those regulatory/policy goals. Dr. Lesser notes that there is an inherent circularity in how Energy Transition risk should be treated. If, for example, legislators pass a law guaranteeing recovery of all potential stranded costs that may arise from the Energy Transition, then there is

[155] Exhibit B1-9, BCUC IR 4.1.
[156] Exhibit B1-8, p. 3.
[157] Exhibit B1-9, BCUC IR 4.1.
[158] Exhibit B1-8, p.3; Exhibit B1-8-1, Appendix A, p. 4.
[159] Exhibit B1-8-1, Appendix C, pp. 73, 90.
[160] Ibid., p. 90.

little additional financial risk to the utility. But if regulators are hostile to stranded cost recovery, then financial markets may require a premium to provide funds to the utility.[161]

Positions of Parties

BCOAPO submits that Energy Transition also includes elements of risk associated with Price (e.g. carbon taxes), Regulatory (e.g. increased complexity and need for flexibility) and Supply (e.g. issues related to Renewable Gas). BCOAPO accepts that political considerations driven by climate change are the impetus behind the risks associated with Energy Transition. However, to the extent current implemented policies addressing climate change concerns are identified and assessed in the consideration of the risks associated with FEI's other risk categories, such policies should not also be identified as political risk. [162]

The CEC submits, "the Energy Transition risks are real and moving quickly in BC" and the BCUC "needs to give significant weighting to the importance of the existential issues facing FEI."[163] However, the CEC finds FEI's risk analysis to be overstated and expects that FEI' s risk will be largely mitigated by new technologies and future developments.[164] Further, the CEC suggests there may be value in separating "the Energy Transition issue out when assessing FEI' s business risk, and evaluate this risk independently against time and other comparable utilities in Canada and the US, instead of addressing it in multiple areas and muddying the other analyses."[165] The CEC submits that it might be appropriate and in the public interest for the BCUC to determine an established risk factor that can be incorporated into FEI' s financial analyses to account for stranded asset risk.[166]

RCIA explains that the issue of Energy Transition "is not new" and "will be with us for a long time."[167] RCIA submits that FortisBC's business risk narrative identifies the same underlying challenges (e.g. climate change policies) as multiple different business risks. RCIA argues that FortisBC exaggerates the depth and breadth of those risks, as it fails to consider to what extent the various risks are duplicative, overlapping or are simply unlikely to result in any material and unrecoverable losses.[168]

MoveUP advocates for "explicit recognition" of diverging impacts, risks and opportunities arising between electric and gas utilities and that this is "foundational to achieving an orderly and rational response to evolving climate policy, including electrification."[169] MoveUP submits that unless carefully calibrated, increasing a gas utility's ROE to manage transition risk could potentially magnify risk and be self-defeating in the longer term.[170]

In reply, FortisBC states that Energy Transition represents a fundamental change that has a pervasive impact on FEI's business.[171] Additionally, FortisBC submits that the Energy Transition is a "notable" area "where BC is markedly different," and where FEI's risk has increased the most since the FEI 2016 COC proceeding.[172] More

[161] Exhibit A2-24, BCOAPO IR 14.3 and 14.4.
[162] BCOAPO Final Argument, p. 15.
[163] The CEC Final Argument, p. 48.
[164] Ibid, p. 28.
[165] Ibid., p. 11.
[166] Ibid., p. 3.
[167] RCIA Final Argument, p. 30.
[168] Ibid., p. 4.
[169] MoveUP Final Argument, pp. 1–2.
[170] Ibid., p. 2.
[171] FortisBC Reply Argument, p. 17.
[172] Ibid., p. 15.

details of FortisBC's reply to intervener arguments on Energy Transition risk are presented under individual risk categories below.

Business Profile

Business profile risk, as defined by FortisBC, is determined by analyzing the type and size, service area, and customer profile of a utility, which are its fundamental characteristics.[173] FortisBC explains that FEI's primary market continues to be residential and commercial space and water heating end-uses. Further, despite some shift in load to the more volatile / sensitive industrial and low carbon transportation sectors, FEI assesses its overall business profile risk to be similar to that in the FEI 2016 COC proceeding.[174]

Positions of Parties

BCOAPO and the CEC agree with FortisBC's business profile assessment.[175]

Economic Conditions

FortisBC assesses that the current Canadian economic environment continues to be dominated by uncertainty and explains that "the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth points to higher risk."[176] Mr. Coyne also comments that the war in Ukraine, aggressive federal action on interest rates, historic high levels of inflation, and pull back on the fiscal stimulus required to support the pandemic ailing economies in Canada and the US have had significant impacts on capital markets in 2022.[177] However, FortisBC does explain that FEI's operations and maintenance (O&M) expenditures and growth capital are indexed to a composite inflation factor (minus a productivity factor of 0.5 percent) and are less impacted by high inflation rates, but FEI's sustainment capital is forecast.[178] FortisBC also notes that utility stocks are generally characterized as defensive and most investors holding utility stocks expect that utility earnings remain stable and grow slowly in most economic conditions.[179]

Positions of Parties

BCOAPO agrees that there is both greater uncertainties associated with the economic outlook for BC (and Canada), particularly in the short-term, and lower prospects for longer term growth.[180] However, the CEC recommends that the BCUC assign no weight to 'Economic Conditions' as a risk factor, as the CEC submits that almost all these items may all be considered as undiversifiable risk. The CEC states that there is little evidence to support a finding that FEI experienced economic woes to a greater extent than those of other utilities, and that this should be considered as conjecture at best.[181]

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[173] Exhibit B1-8-1, Appendix A, p. 8.
[174] Ibid., pp. 3–4.
[175] BCOAPO Final Argument, p. 14, The CEC Final Argument, p. 13.
[176] Exhibit B1-8-1, Appendix A, p. 4.
[177] Transcript Volume 3 – Proceedings November 7, 2022, p. 158.
[178] Exhibit B1-9, BCUC IR 13.1.1.
[179] Ibid., BCUC IR 21.1 and 21.1.1.
[180] BCOAPO Final Argument, p. 14.
[181] The CEC Final Argument, pp. 13–14.

In response, FortisBC argues that similar macro-economic conditions can still lead to different impacts on different utilities based on the particular characteristics of the utility and its jurisdiction.[182]

Political

FortisBC considers political risk to be "the most notable of all of the risk factors."[183] FortisBC explains that government policies and regulations at all levels, as well as stakeholder interests, have a significant impact on FEI's operations, competitiveness, and ability to achieve its important initiatives. Additionally, FortisBC stresses, "[t]he overall thrust of climate change and energy policies is moving at a more rapid pace than at the time of the 2016 Proceeding and the role of natural gas, or even Renewable Gas, within the province's future energy landscape is unclear."[184]

While FEI believes that gas infrastructure is an optimal tool to reach decarbonization goals, there is a lack of awareness and acceptance of that role, given it is not directly discussed in net zero climate goals and plans. FortisBC states that this is apparent in the provincial government's recently updated Roadmap which is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for customer rates and throughput. FortisBC states that the risk is further compounded by the fast pace of legislation and policies on electrification initiatives which increase competition with electricity. FortisBC assesses that FEI's political risk has increased significantly relative to the political risk environment at the time of the FEI 2016 COC proceeding.[185]

Positions of Parties

BCOAPO accepts that political risk faced by FEI has increased, primarily because governments are now clearly paying attention to and responding to climate change concerns, and acknowledges that there is also political risk associated with the lack of government direction regarding the role BC gas utilities will play in addressing climate change concerns.[186] BCOAPO views that "the critical aspect regarding political risk is the uncertainty regarding future policies and the impact they will have on FEI's business."[187] The CEC agrees that there is a growing bias against the use of natural gas on the part of multiple policymakers. The CEC suggests, there should be consideration for other political risks such as the "significant political upheaval in the US over the last few years"[188] and that it is important that the BCUC not overlook other aspects of the political environment when considering FEI' s political risk.[189]

With respect to the CEC's arguments regarding political upheaval in the US, FortisBC submits that the "BCUC should not consider the new and untested information. In any event, the link between political upheaval in the US and policies around the Energy Transition are not immediately apparent."[190]

[182] FortisBC Reply Argument, p. 18.
[183] Exhibit B1-8-1, Appendix A, p. 4.
[184] Ibid.
[185] Ibid.
[186] BCOAPO Final Argument, pp. 15–16.
[187] Ibid.
[188] The CEC Final Argument, p. 16.
[189] Ibid., p. 17.
[190] FortisBC Reply Argument, p. 19.

RCIA states that FEI's business risk narrative identifies the same underlying challenges (i.e. climate change policies) as multiple different business risks, which RCIA notes, does not provide clear, objective evidence validating an absolute increase in business risk.[191] RCIA submits that climate change and related topics have been part of the public discourse for many years and is not a new issue.[192] In reply, FortisBC states that FEI has not claimed that policy risk is new per se, but rather has demonstrated that the risk is significantly higher than at the time of the FEI 2016 COC proceeding.[193]

Indigenous Rights and Engagement

FortisBC has assigned Indigenous Rights and Engagement risk its own category in this proceeding (previously subsumed under political risk) to reflect the increasing significance of these considerations for FEI's overall business. This risk assesses the potential for utility operations to be impacted by policy or legislation concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. As provincial and federal governments navigate reconciliation and implement the UN Declaration on the Rights of Indigenous Peoples, FEI has assumed a higher level of business risk related to its relationship with Indigenous groups compared to what it anticipated at the time of the FEI 2016 COC proceeding.

FortisBC explains most land in BC is not subject to treaty (the land is unceded), and most Indigenous groups in BC are not signatories or adherents to a treaty (historic or modern) unlike in many other provinces. FortisBC states that Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FEI operates. Most of FEI's operations are in areas not covered by treaty, meaning that these areas are subject to assertions of Aboriginal title and may be subject to legal claims for title in the future. However, FEI also has some operations in treaty areas. Combined with regulatory updates that have increased consultation requirements and include a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FEI considers that it faces an elevated risk of cost escalation, project delays, and/or projects being denied approval.[194]

Positions of Parties

BCOAPO agrees that FEI faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of the FEI 2016 COC proceeding. However, BCOAPO notes that FEI has not been a party to any litigation initiated by Indigenous groups based on the duty to consult in either the five-year period prior to or since the FEI 2016 COC proceeding and has not faced any formalized work disruptions (e.g. protests or blockades) initiated by Indigenous groups, and no projects have been denied as a result of issues regarding the duty to consult with Indigenous groups. Similarly, FEI is not currently involved in any judicial reviews based on claims of inadequate consultation or other Indigenous rights litigation.[195]

[191] RCIA Final Argument, p. 31.
[192] Ibid., pp. 29–30.
[193] FortisBC Reply Argument, p. 20.
[194] Exhibit B1-8-1, Appendix A, pp. 4–5, 44.
[195] BCOAPO Final Argument, p. 17.

BCOAPO also highlights that FEI has mitigation in place as it actively addresses the risks associated with its increased duty to consult by reaching out to Indigenous groups early (sometimes in absence of a Crown determination), as "FEI's goal is to engage early, often, and thoroughly."[196] BCOAPO is also concerned that there is overlap and double-counting with FEI's Regulatory risk, differentiating that "the duty to consult on projects (prior to making applications to regulatory bodies) should be considered an Indigenous Rights and Engagement risk, while the increase in interventions and participation by Indigenous groups in regulatory processes should be considered a Regulatory risk."[197]

In response to BCOAPO, FortisBC states that its business risk assessment already accounts for mitigation and investors are aware of publicly available information, including plans, strategies and capital investments that would mitigate the utilities' risk.[198] In regards to double-counting and overlap, FortisBC states its risk analysis is a holistic assessment of a complex matrix of factors affecting different aspects of FEI and FBC's businesses, and FortisBC has never suggested that the BCUC's role is to carry out a rote tallying of categories.

FortisBC explains investors will inevitably approach risk assessment in different ways, but the ultimate objective will always be to assess the potential for not earning a return on and of invested capital. The risk categories that FortisBC has employed are a useful presentation format for identifying the types of considerations that inform investment decisions and are consistent with the categories and factors used in previous cost of capital proceedings, thus facilitating comparisons over time.[199]

The CEC recommends that the BCUC find the Indigenous Rights and Engagement concerns to be largely mitigatable and less risk than that in 2016. The CEC submits that many utilities face issues with respect to Indigenous Rights and Engagement issues, and so the risk may be somewhat undiversifiable. The CEC argues that provincial policy has been made clearer, given certain pronouncements mandating steps to entities dealing with Indigenous Peoples which were not clearly mandated in 2016.

The CEC notes that there has been considerable movement regarding Indigenous Peoples for engaging in reconciliation activities and the CEC expects that this may turn from being a risk increase to being a positive reduction of risk.[200] The CEC also submits that this category should be included in the political category as it was previously. The CEC states that it is important for the BCUC to exercise caution when separating out items that were previously considered together, in that it potentially leads to selection or framing bias, and weighting becomes more difficult.[201]

In response to the CEC, FortisBC argues that utilities in BC are exposed to unique risks because, unlike in other provinces, most land is not subject to treaty (the land is unceded), and most Indigenous groups in BC are not signatories or adherents to a treaty (historic or modern).[202] Further, FortisBC's "commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate risk, and FEI's risk assessment is post-mitigation."[203] FortisBC argues that business uncertainty associated with Indigenous Rights and

[196] BCOAPO Final Argument, p. 18.
[197] Ibid., p. 17.
[198] FortisBC Reply Argument, p. 11.
[199] Ibid., p. 5.
[200] The CEC Final Argument, p. 18.
[201] Ibid., p. 17.
[202] FortisBC Reply Argument, pp. 20–21.
[203] Ibid.

Engagement has increased since the FEI 2016 COC proceeding.[204] Finally, FortisBC submits that trying to recategorize risks at this point would be counter-productive.[205]

Energy Price

FortisBC states the risk relating to energy prices is higher than what it was during the FEI 2016 COC proceeding. FortisBC explains that energy prices impact a utility's business risk because price is among the factors that can influence consumer energy choices. It argues that FEI's overall energy price risk is higher due to:[206]

- Natural gas commodity prices being higher: Current market prices for natural gas are higher than in 2015 and forecasted to increase as demand from power generation and liquefied natural gas (LNG), and a potential decline in crude oil production, puts pressure on prices;
- Natural gas prices being more volatile: Market prices are expected to remain volatile as a result of extreme weather events, changes in natural gas demand for power markets in the region, and anticipated growth in demand to supply the LNG export market. The volatility is greater than that presented in the FEI 2016 COC proceeding; and
- Subsidies and tax incentives / disincentives making electric appliances cheaper than gas appliances: The current price advantage of natural gas versus electricity is not expected to be maintained, especially with recent rate announcements from BC Hydro which will see electricity rates held fairly flat over the next several years. Current and planned increases in carbon tax rates will continue to negatively affect natural gas price competitiveness relative to electricity.

Further, the increasing share of higher cost Renewable Gas in FEI's gas supply portfolio contributes to FEI's higher price competitiveness risk as Renewable Gas is more expensive than natural gas. Moreover, new technology which supports the use of electricity, such as electric heat pumps, that have a higher upfront and installation cost than natural gas-fired equipment, are more cost competitive when government-provided incentives and rebates are considered.[207]

Positions of Parties

BCOAPO agrees that FEI's energy price risk has increased since the FEI 2016 COC proceeding. However, based on BCOAPO's view that natural gas commodity risk is similar to that in 2015 for the long term, BCOAPO does not view FEI's energy price risk as having increased to the same degree as suggested by FEI.[208] BCAOPO notes that when natural gas commodity prices are looked at in real terms (i.e. adjusted for inflation) current commodity prices are high relative to those in 2015. However, forecast commodity prices (post 2023) are in line with those from 2015 to 2016. However, BCOAPO does agree with FortisBC with respect to increased natural gas price volatility and decreased competitiveness.[209]

[204] FortisBC Reply Argument, p. 21.
[205] Ibid., p. 6.
[206] Exhibit B1-8-1 Appendix A, pp. 53–78.
[207] Ibid., pp. 5, 70.
[208] BCOAPO Final Argument, pp. 18–19.
[209] Ibid., p. 19.

In reply, FortisBC submits that BCOAPO's attempt to downplay the risk is incongruous with its acknowledgement that current commodity prices are high relative to those in 2015 and its agreement about increased price volatility and decreased competitiveness.[210]

The CEC recommends that the BCUC finds the energy price risk to be similar to 2016 and assign limited weight to energy price as a risk category. The CEC does not agree that an increase in natural gas price will necessarily equate to an increase in the risk that the company will not recover its ROE, as the higher price is caused by increasing demand. The CEC submits that "this approach to assessing risk is not consistent with the definition of risk as it relates to achieving ROE but is rather FEI's shotgun and 'general impression' approach to including any number of possible items without refining the analysis to assess whether or not it actually results in risk to the utility in its ability to achieve its ROE."[211]

The CEC accepts that price competitiveness and the narrowed cost differential with electricity potentially represent something of a higher risk. However, the CEC submits that the cost of adding renewable natural gas supply to the portfolio should be treated as a mitigating factor with respect to the effects of the Energy Transition and will likely serve to mitigate the political, regulatory and customer risk. Finally, the CEC expects volatility may have little impact on the ability of the utility to recover its ROE.[212]

In reply to the CEC, FortisBC argues that FEI is purchasing more renewable gas to mitigate its Energy Transition risk, but that does not mean its energy price risk is not higher because of it. FortisBC states, FEI is not required to demonstrate that it will not recover its ROE, but rather, in the long term, investors would perceive risk to the recoverability of their invested capital from an increase in the risk related to energy price. FortisBC submits that the CEC is "conflating investor-perceived risk (the relevant consideration in cost of capital analysis) with actuarial risk (an irrelevant consideration)."[213]

MoveUP submits, as gas commodity and delivery costs increase relative to electricity, more customers will prefer electric energy solutions, adding yet another accelerator to declining customer growth and a core customer base will be left to bear the utility's fixed costs and return on its invested capital. Responding to this risk cycle by increasing ROE without regard to these impacts would add fuel to the fire. MoveUP states that the BCUC must be mindful of the rate impacts of risk-based increases in gas utilities' rates of return to avoid a dynamic where satisfying immediate return entitlements accelerates a potential capital funding crisis over time. MoveUP argues that rewarded capital today could become stranded capital earlier in the future.[214]

In reply to MoveUP, FortisBC explains that all rising costs, not just increasing cost of capital, affect a utility's competitiveness; all prudent costs of providing utility service, including cost of capital, must be recovered. FortisBC submits that FEI needs to be well-financed to navigate the Energy Transition and encouraging the flight of capital away from a capital-intensive business is a poor recipe for success.[215]

[210] FortisBC Final Argument, p. 21.
[211] The CEC Final Argument, pp. 19–20.
[212] Ibid., p. 20.
[213] FortisBC Reply Argument, p. 22.
[214] MoveUP Final Argument, p. 3.
[215] FortisBC Reply Argument, pp. 3–4.

Demand/Market

FortisBC states overall, since the FEI 2016 COC proceeding, FEI's demand/market risk has increased. FortisBC states that customer energy choices have had the tendency to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. However, FortisBC explains that demand and market changes pose challenges to FEI's ability to attract and retain customers and maintain market share and throughput levels driven by:[216]

- BC residents' worsened perception of natural gas as customers' energy choices are increasingly influenced by a desire to minimize negative environmental impacts;
- New technologies and building techniques, supported by policies that are negatively affecting gas demand;
- While Renewable Gas can be a relatively affordable option, the electric options such as high-efficiency heat pumps are gaining faster and more widespread traction among customers and policy makers;
- FEI experiencing a downward trend in net residential customer additions and in its share of natural gas use in space heating and water heating applications;
- In the residential sector, where due to BC's high turnover rate, a large segment of its existing customers' homes may be torn down and rebuilt with electric-only options to meet more stringent code requirements;
- FEI's risk profile which continues to be impacted by the gradual decline in single-family dwellings, where FEI has higher capture rates in favour of multi-family dwellings; and
- FEI's new residential customers who continue to have lower use per customer (UPC) than average residential customers do,[217] although this is somewhat offset by load growth in the more volatile and economically sensitive transportation and industrial sectors.[218]

FortisBC states that all of these factors create challenges for natural gas utilities in retaining and attracting load, despite lower natural gas commodity prices relative to other energy forms. [219]

Positions of Parties

BCOAPO submits that FEI's assessment of the increase in risk associated with Market/Demand is overstated.[220] BCOAPO submits that recent trends in UPC have been more favourable than those leading up to the FEI 2016 COC proceeding and argues that increases in UPC for the non-Residential sectors have more than offset any trend to lower UPCs in the Residential sector.[221] BCOAPO views there is overlap (and likely double counting) between the various factors assessed under Market/Demand, as the increased use of electric heat pumps is a consideration for 'New Technology and Energy Forms' but is also a contributor to the risk assessment with respect to 'Net Customer Additions' and 'Changes in end-use Market Share'.[222]

[216] Exhibit B1-8-1, Appendix A, pp. 5, 78–88.
[217] Ibid., p. 5.
[218] Ibid., p. 57.
[219] Ibid., p. 78.
[220] BCOAPO Final Argument, p. 22.
[221] Ibid., pp. 21–22.
[222] Ibid., p. 22.

In reply to BCOAPO, FortisBC submits that in the context of the Energy Transition, the past is not the best predictor of the future and several factors that are expected to impact FEI's market share and UPC, such as electric heat pumps, are expected to reduce UPC, and municipal policy is expected to reduce FEI's ability to connect to new customers.[223]

The CEC recommends that the BCUC find there to be similar risk as those found in 2016 based on the evidence in the FEI Long Term Gas Resource Plan (LTGRP) proceeding and avoid unduly exaggerating the political risk of the Energy Transition when considering this category.[224] Moreover, the CEC notes that declining market share does not necessarily represent declining revenues or an inability for the utility to achieve its ROE and that most of the risk areas identified in demand/market risk are at least largely captured in political risk.[225]

In reply to the CEC, FortisBC submits that FEI's evidence in this proceeding on demand/market risk is consistent with the LGTRP proceeding. FortisBC also submits that a reasonable investor would perceive risk to their prospects of recovery in light of FEI's diminishing market share. FortisBC explains that investors take a long-term view of risk and would negatively perceive declining market share. A smaller customer base generally means that the revenue requirements are recovered from fewer customers over fewer billing determinants. An investor considering long-term risk will realize that this pattern will increase the prospects of further loss of market share and even higher rates (i.e. a spiral).[226]

RCIA submits that expansion opportunities are particularly relevant to FEI's overly conservative projections and that realistically, FEI's revenues could be substantially higher in the near future than they are currently. This windfall opportunity should substantially offset many of the business risks alleged by FEI.[227] RCIA also notes that "FEI's annual demand forecast indicates expected demand over the next 3-5 years (and longer) will be strong, even under worst-case scenarios."[228]

In reply to RCIA, FortisBC states that FEI's primary business continues to be in serving space and water heating load in the residential and commercial sectors. FortisBC submits that focusing only on overall units of energy demand from FEI distracts from the other risk factors affecting the demand/market risk category, including downward changes in end-use market share, downward trends in net customer additions, and increased gas supply costs. These trends are indicative of longer-term risk, which is the focus of risk assessment, not three to five year forecasts. In addition, adding load from LNG to the core residential and commercial sectors to mitigate load losses in exposes FEI to higher revenue (and potentially earnings) volatility.[229]

Energy Supply

FortisBC states, relative to 2015 levels, FEI's energy supply risk remains similar. FortisBC notes that availability and accessibility of natural gas supply to FEI's service territory remain unchanged, as natural gas producers forecast production increases to meet demand growth for gas-fired power generation and LNG. Additionally, FEI

[223] FortisBC Reply Argument, pp. 22–23.
[224] The CEC Final Argument, p. 22.
[225] Ibid., pp. 21–22.
[226] FortisBC Reply Argument, pp. 23–24.
[227] RCIA Final Argument, p. 26.
[228] Ibid., p. 27.
[229] FortisBC Reply Agrument, pp. 24–25.

continues to rely on a single system for a significant portion of its gas requirements.[230] FortisBC has also added a new risk factor to this category, 'Renewable Gas Supply', which it deems as higher change in risk since 2016, albeit there is no change in the overall risk category. FortisBC argues that there is increased risk arising from issues with suppliers, competition for Renewable Gas supply, and barriers to gas system readiness and acceptance of non-local supply.[231]

Positions of Parties

BCOAPO agrees with FEI's risk assessment regarding natural gas commodity supply and access. The CEC recommends that the BCUC find the energy supply risk to be similar to that in the FEI 2016 COC proceeding while assigning moderate weight to this category.[232]

Operating

FortisBC submits that operating risk includes the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather.[233] FortisBC explains that operating risk factors continue to include infrastructure integrity and time dependent threats, along with third-party damages and unexpected events (including the COVID-19 pandemic, Enbridge T-South pipeline rupture, as well as more frequent extreme weather events).[234] While these types of operating risks have always been present, there is a growing recognition in the industry of utility exposure to significant unforeseen events and the importance of resiliency.[235]

FortisBC acknowledges that there is a risk management process for FEI's reliability and resiliency integrity projects, and it prioritizes the projects based on the importance of managing those risks.[236] Of note, FEI has also added several new risk factors to this category (including attitudes towards fossil-fuel industry, municipal operating challenges, and cybersecurity), which it deems as higher change in risk since 2016 and contribute to the overall risk category assessment as higher.[237]

FortisBC submits that the negative public sentiment towards the fossil-fuel industry may hinder FEI's ability to recruit skilled workers, complete already approved projects on time and budget, meet environmental and safety requirements or obtain the necessary approvals and operating permits. Additional municipal requirements and associated costs arise in the context of both FEI's ongoing operating and maintenance activities and its larger construction projects. These additional requirements may result in increased costs to FEI or challenges requiring additional time to resolve. FortisBC submits that its approach is to manage these additional requirements by negotiating an acceptable compromise with municipalities, and typically, FEI and the municipality are able to reach a compromise, which is consistent with FEI's rights and obligations.[238]

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[230] Exhibit B1-8-1, Appendix A, p. 6.
[231] Exhibit B1-8-1, Appendix A, pp. 97–107.
[232] BCOAPO Final Argument, p. 22, The CEC Final Argument, p. 23.
[233] Exhibit B1-8-1, Appendix A, p. 108.
[234] Ibid., p. 6.
[235] Exhibit B1-8, p. 16.
[236] Oral Hearing Transcript, Volume 5B, p. 887.
[237] Exhibit B1-8-1, Appendix A, p. 2–3.
[238] Ibid., p. 111.

Positions of Parties

BCOAPO agrees that FEI's operating risk has increased but not to the degree implied by FEI.[239] BCOAPO notes that there is a potential overlap of contributors in the operating risk category as to FEI's political risk with respect to attitudes towards the fossil-fuel industry, including the province's updated Roadmap, which are increasing concerns around natural gas utility activities and increasingly strict environmental and safety laws, regulations and enforcement policies since 2015.[240] BCOAPO also states that "there is no reference in the evidence presented to a successful cyber-attack on FEI that impacted its operations" and that while BCOAPO "acknowledges that lack of occurrence does not mean a risk does not exist", in BCOAPO's view, "past occurrences do provide an indication as to the degree of risk involved."[241]

In reply to BCOAPO, FortisBC states that the lack of a previous occurrence does not mean a risk does not exist and points to the fact that utilities such as FEI are vulnerable to cyberattacks and the consequences may be severe.[242]

The CEC submits that, overall, the operating risk for FEI is at least similar, if not better, than that during the FEI 2016 COC proceeding due to the new capital projects likely to be undertaken to enhance reliability and resiliency and recommends that the BCUC assign moderate weight to this category.[243] The CEC submits that there are very substantial resources being devoted to mitigating the risks and recommends that the BCUC weigh the value of these risk mitigation and resiliency projects significantly to avoid having ratepayers fund the projects without having the associated risk reduction recognized financially in the setting of the ROE.[244] The CEC "expects that cyber security may be a higher risk, but also notes that this is an undiversifiable risk in that nearly all companies are facing increased issues in this field."[245]

In response to the CEC, FortisBC argues with respect to new projects, FEI's risk assessment is post-mitigation, some of these projects have not yet been approved and implemented, and that cybersecurity risk is "increasingly gaining weight in investors' perception of risk."[246]

RCIA submits that although unpredictable weather is an operational challenge, it is not clear the potential impact of unpredictable weather is a genuine threat to FortisBC achieving its approved ROE or return of capital, as it is not clear that extreme weather events will impede FortisBC's ability to achieve its ROE or that associated costs will not be recoverable through rates or government funding.[247]

In reply to RCIA, FortisBC states that it is not required to demonstrate that each risk factor will impede FEI's ability to achieve its ROE, only that investors would perceive a long-term risk of recovering their investment. Considering FEI's recent experience with a high volume of high-impact weather events, FortisBC submits that a reasonable investor would perceive an elevated level of risk.[248]

[239] BCOAPO Final Argument, p. 23.
[240] BCOAPO Final Argument, p. 23.
[241] Ibid.
[242] FortisBC Reply Argument, p. 25.
[243] The CEC Final Argument, p. 24.
[244] Ibid.
[245] Ibid.
[246] FortisBC Reply Argument, p. 26.
[247] RCIA Final Argument, p. 30.
[248] FortisBC Reply Argument, p. 26.

Regulatory

FortisBC states that as a regulated public utility, FEI is dependent on regulators for timely and fair approvals to earn its return on and of capital, which results in regulatory risk.[249] FortisBC explains that there is an increased level of regulatory uncertainty and increased potential for regulatory lag in both BCUC and other regulatory processes.[250] FortisBC has assessed FEI's overall regulatory risk as higher than what was assessed in the FEI 2016 COC proceeding, with certain risk factors increasing and others being similar. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved.

The underlying BCUC regulatory framework remains the same, but there are new developments that merit note. There is uncertainty caused by the level of regulatory support for the implementation of certain initiatives and the BCUC's decision to consider a more generic approach to deferral account financing treatment. FortisBC also mentions there are increased requirements for stakeholder consultation, environmental reviews, Indigenous rights and title, and municipal operating challenges.[251]

Positions of Parties

BCOAPO acknowledges that BCUC has discretion which, inherently, creates risk, but points out that FortisBC has acknowledged that it "generally finds the BCUC's decisions to be well reasoned (irrespective of whether a decision is favourable to FortisBC or not)."[252] BCOAPO submits that "the requirement for seeking the free, prior and informed consent ("FPIC") of Indigenous Peoples before proceeding with project development and, in particular, before proceeding with an application for regulatory approval (from the BCUC or any other approval authority) is a legitimate risk. However, it should not be double counted" and "not included in the assessment of Regulatory risk as FEI has done."[253] With respect to FortisBC's concerns regarding deferral account financing, BCOAPO submits that both FEI and FBC will have a full opportunity to present their views and that "the BCUC is open to considering specific circumstances after it has made decisions on a generic basis."[254]

In response to BCOAPO, FortisBC argues that "the fact a BCUC decision is well-reasoned does not mean the decision will be favourable from an investor's perspective."[255] Furthermore, with respect to double-counting, FortisBC submits that "recategorizing these distinct impacts does not make the risk any less real to investors."[256]

The CEC recommends that the BCUC find the regulatory environment to be generally favourable and the risk similar as in 2016.[257] The CEC submits that there is little regulatory risk associated with a utility not being enabled to earn a fair return and what may be considered as 'generally fair' regulation should not be interpreted

[249] Exhibit B1-8-1, Appendix A, p. 115.
[250] Exhibit B1-8-1, Appendix A, p. 115.
[251] Ibid., pp. 6–7.
[252] BCOAPO Final Argument, p. 25.
[253] Ibid.
[254] Ibid.
[255] FortisBC Reply Argument, p. 26.
[256] Ibid., p. 27.
[257] The CEC Final Argument, p. 27.

to have significant risk.[258] With respect to approvals, the CEC submits that the 'lack of assured approval' should not be equated with significant risk or that the utility will not be given its opportunity to earn a fair return.[259] Furthermore, the CEC notes that most utilities suffer from regulatory lag and submits that the "issues related to Indigenous communities and municipal challenges have been fully addressed in Indigenous Rights and Engagement and political risk and should not be re-reviewed in Regulatory Risk."[260]

In response to the CEC, FortisBC argues that utilities have lower overall returns (combined equity ratio and ROE) relative to the market; the rate regulator has discretion over setting the allowed ROE and other decisions that can have a material impact on the long-term success of the utility; short-term regulatory risk also arises from rates being set on a forecast basis; and FEI is subject to a number of other regulatory regimes, including Environmental Assessment processes, municipal requirements, and the requirements and processes of Indigenous communities.[261]

Panel Determination

Although the business risks presented by FEI are categorized, we consider business risks holistically since a utility is affected by the interplay between all its business risks, some of which may offset others.

Business risk evaluation is a matter that does not lend itself to a simple delineation of items into absolutely discrete categories. Nor does it lend itself to the application of an algorithm or equation in a purely mechanistic manner to calculate risk either overall or by category. Thus, the Panel accepts that there is inevitably some overlap between the business risk categories but does not consider this to be problematic.

The Panel accepts that FEI used the same risk categories as in the FEI 2016 COC proceeding thus facilitating comparisons over time. Additionally, the Panel considers it reasonable to expect that new business risk factors will emerge over time such as the Indigenous Rights and Engagement risk which has been promoted to its own risk category in this proceeding. Overall, the Panel considers that the categories of business risk and the risk factors are reasonable and appropriate, however are not all equal, for the purposes of evaluating overall changes in business risk for FEI.

The Panel notes costs associated with certain risk categories such as commodity prices and Indigenous engagement activities will largely be borne by ratepayers since increases in operating costs and capital projects are generally recoverable through rates. In contrast, some elements of Energy Transition risk pose an existential risk to FEI's shareholders and impact the risk of stranded assets which increases the risk that shareholders will not be able to earn their full return. Therefore, the Panel will not consider changes in ratepayer risks in isolation as changes to FEI's overall business risk.

In order to assess the extent of the impact of changes in business risks on shareholders' expected return, the Panel needs to consider investors' perceptions of business risks in addition to the real business risks that have emerged in the last few years. A cumulation of perceived ratepayer risks could shift the risk to the shareholder if

[258] The CEC Final Argument, pp. 27–26.
[259] Ibid., pp. 25–26.
[260] The CEC Final Argument, p. 25.
[261] FortisBC Reply Argument, pp.27–28.

the utility is no longer viewed as an attractive investment. Both experts, Mr. Coyne and Dr. Lesser, agree that if perceived risks are commonly believed, they will be relevant to the calculation of expected returns.

The Panel will not review all of the submissions made by FEI and interveners on the various business risk categories. Instead, we will focus on how FEI's various business risk categories have changed since 2016 from a shareholder and investor perspective. Thus, we have not focused on business profile and energy supply risk categories, as we agree that both are similar to 2016 and no parties raised an issue with FEI's assessment. We note that changes in business risks for an investor must also be considered, in part, relative to comparable entities, not just against itself at a previous point in time. Therefore, we will focus on those areas where FEI has noted changes in risk and discuss whether we agree with FEI's assessment of those changes and whether they increase risk, real or perceived, to the shareholder and investor as opposed to the ratepayer. We begin our analysis with an assessment of FEI's economic conditions risk below.

Economic Conditions

FEI submits that the economic condition risk has increased largely due to inflation increases caused by the current economic environment. The Panel notes that FEI has not provided price-elasticity evidence that demonstrates inflationary pressures on rates have caused, or will cause, a reduction in consumption. Evidence presented indicates that energy customer retention is influenced by the worsening perception of natural gas but not by increases in inflation. Additionally, the Panel notes that FEI is continuing to forecast customer additions in the prevailing economic conditions.

The Panel acknowledges that economic conditions are different than in 2016; however, we are not convinced that this risk results in any increased real risk to the shareholder or investor as FEI's O&M expenditures, and its growth capital are currently indexed to a composite inflation factor under its multi-year rate plan and are recoverable from ratepayers. If this mechanism wasn't effective, the Panel expects that FEI would make an application to the BCUC to correct it.

Similarly, while there may be a higher risk of the economy worsening, the Panel is not persuaded that this will result in investors perceiving FEI or any utility stocks to be less attractive as a result. As noted by FortisBC, utility stocks are characterized as defensive and investors holding utility stocks expect earnings to remain stable and grow slowly in most economic conditions. Therefore, the Panel disagrees with FortisBC's assessment that the economic conditions pose a higher risk to FEI's shareholder and investors than in 2016, as this is a risk borne by the ratepayer. Accordingly, **the Panel finds that the economic conditions risk for FEI's shareholder and investor is similar to what it was in 2016.**

Political

FortisBC notes that the Energy Transition risk is apparent in the BC government's recently updated Roadmap which is anticipated to have a significant impact on FEI's competitive and operational landscape, resulting in FEI to assess its political risk as significantly higher than 2016. The evidence shows that the Energy Transition represents a fundamental change that has a pervasive impact on FEI's business and that the change in BC is markedly different than in other jurisdictions as a result of government policies relating to climate change, decarbonization and electrification that have emerged since 2016. The Panel considers this to be the biggest driver of real and perceived risk for FEI's shareholder primarily as a result of all levels of government addressing

climate change concerns and the uncertainty regarding the role that BC's natural gas utilities will play in addressing climate change concerns, especially when compared to utilities operating in other jurisdictions since the FEI 2016 COC proceeding.

The Panel agrees with BCOAPO that "the critical aspect regarding Political risk is the uncertainty regarding future policies and the impact they will have on FEI's business" [262] and agrees with the CEC that there is a growing bias against the use of natural gas on the part of multiple policymakers. Accordingly, **the Panel finds that the political risks faced by FEI's shareholders have increased significantly since 2016.**

Indigenous Rights and Engagement

FEI assesses its business risk related to relationships with Indigenous groups in BC as higher relative to the time of the FEI 2016 COC proceeding. The Panel acknowledges there are uncertainties and unknowns, as FEI's operations are subject to land claims due to the lack of treaties in BC compared to other parts of Canada which add to the perceived risks for FEI's investors. This uncertainty is greater for FEI relative to other utilities in North America, but the Panel finds it hard to determine the precise magnitude of that difference and how it might change in the future. The Panel also notes that while project approvals for FEI are potentially impacted due to concerns in this area, the costs associated with these impacts are largely a ratepayer risk, as they are recoverable through rates.

BCOAPO agrees with FortisBC that FEI's risk is higher from 2016 but notes that FEI is not involved in any litigation initiated by Indigenous groups. The Panel is not persuaded by BCOAPO's comments. While FEI may not be involved in Indigenous litigation now or in the past, this does not diminish investors' perception that this risk exists, especially operating on unceded land. The CEC submits that Indigenous risk should be considered less risky than that in 2016, as it is largely mitigatable. The Panel disagrees. Rather, we agree with FortisBC that its commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate investors' perception of Indigenous risks. Therefore, while this risk is largely borne by ratepayers, there is perceived risk by investors that could affect FEI's shareholders. As a result, **the Panel finds that the Indigenous Rights and Engagement risk to FEI's shareholders and investors is higher than it was in 2016.**

Energy Price

FEI's assessment is that the overall real energy price risk is higher than 2016 partially due to volatility in natural gas prices. While the Panel accepts that current natural gas prices are more volatile than in 2016 due to increased weather events, forecast LNG demand growth, and forecasted decreases in oil production, this increase in real energy price risk will be largely borne by the customer through rates. The Panel does note, however, that while natural gas prices are still lower than other forms of energy, as government policies encourage decarbonization by offering subsidies and tax incentives for electric appliances, natural gas' relative price advantage over electricity may not be maintained, thereby increasing perceived risk among investors. BCOAPO agrees with FortisBC except it submits that forecast natural gas commodity prices are in line with those in 2016. The Panel is not convinced that Commodity Price risk being similar to 2016 would offset the increased risk associated with price volatility, but nevertheless the associated costs would be recovered from ratepayers through FEI's rates. The CEC considers energy price similar to 2016, as it submits that adding renewable natural

[262] BCOAPO Final Argument, p. 15.

gas supply to the portfolio should be treated as a mitigating factor with respect to the effects of the Energy Transition and will likely serve to mitigate the political, regulatory and customer risk.

The Panel agrees with FortisBC that as FEI blends higher-cost renewable gas into its portfolio, this will likely serve to put pressure on its price advantage relative to other forms of energy, thereby increasing investors' perception of energy price risk. Therefore, while energy price risk is largely borne by ratepayers, it is reasonable that investors' perception of risk will increase if the relative natural gas price advantage may not be maintained, and this could affect investors' expected return. Accordingly, **the Panel finds that FEI's energy price risk to the shareholder and investor is higher than it was in 2016.**

Demand/Market

FortisBC lists several contributors to the increase in demand/market risk, including the worsening of BC residents' perception of natural gas and the development of new technologies, like electric heat pumps, that aim to shift demand away from natural gas. The Panel accepts that BC residents' energy choices are increasingly influenced by a desire to use energy efficiently, to adopt lower carbon and renewable energy sources, and to generally reduce the negative impacts of climate change leading to a reduction in the end-use market share for natural gas and resulting in an increase in perceived risk by investors and a real risk for shareholders as compared to 2016. The Panel also agrees this is anticipated to result in a future reduction of new customer capture rates and perhaps even attrition of existing customers. Fewer customers to cover costs may result in an increase in natural gas delivery rates for remaining customers.

BCOAPO states that FortisBC's assessment of FEI's demand risk is overstated and points out that increases in non-residential sectors' UPC have more than offset any trend in the lower residential sector UPC. The Panel is not persuaded by BCOAPO's argument, as we find the increased risk in this category to be driven by factors leading to a reduction in the market share for natural gas. However, we find that FEI's customers bear some of this risk, especially those customers that lack the financial means to convert their residences to alternative heating sources to mitigate increasing natural gas costs**.**

The CEC states that the Panel should find there to be similar risk as in 2016 based on the FEI LTGRP proceeding evidence and that declining market share does not necessarily represent declining revenues or an inability for the utility to achieve its ROE. Although the Panel agrees to an extent, we consider that declining market share would be perceived negatively by investors thereby affecting the shareholder's expected returns. Accordingly, **the Panel finds that FEI's demand/market perceived risk for the shareholder and investor to be higher than it was in 2016.**

Operating

FEI submits that, compared to the FEI 2016 COC proceeding, its operating risk has increased. While FEI states that negative attitudes toward the fossil-fuel industry may hinder FEI's ability to recruit workers, complete approved projects, and meet environmental and safety requirements or obtain necessary approvals and permits, no evidence has been provided to indicate this risk is higher than in 2016 or is perceived by potential investors as higher compared to other gas utilities.

The Panel accepts that permitting requirements are changing, which may lead to higher costs related to FEI's ongoing operating and maintenance activities and its larger construction projects. However, FEI did not present evidence that these changing requirements have resulted in expenditures for which it has not received approval to recover from its customers.

FEI also submits that other unexpected events, such as more frequent extreme weather events and increased incidences of cyberattacks, can impact its ability to maintain and operate its system, thereby increasing operating risk. The Panel agrees with FEI that it is not necessary to demonstrate that each risk factor will impede FEI's ability to achieve its ROE. Rather it is incumbent upon FEI to demonstrate that investors perceive a long-term risk of its ability to recover investments. FEI did not present evidence that demonstrates that investors view these risks as being greater for FEI than for other utilities, nor did FEI provide evidence demonstrating that it has been unable to recover its incurred expenditures needed to address these operating risks. Based on the foregoing, the Panel is not persuaded that FEI's overall operating risk has increased for its shareholder since 2016. **The Panel finds that FEI's operating risk is similar to what it was in 2016**.

Regulatory

FEI argues that its overall regulatory risk is higher than what was assessed in the FEI 2016 COC proceeding. FEI submits that regulatory uncertainty gives rise to the risk that the allowed return or rates may not meet the Fair Return Standard, or that necessary investments are not approved. However, FEI provides no evidence that regulatory uncertainty has led to an increase of perceived risk from investors or rates being set at a level that does not provide FEI an opportunity to earn its allowed return. The Panel agrees with the CEC that "the 'lack of assured approval' should not be equated with significant risk."

FEI submits that risk associated with regulatory lag and ultimate approval of cost recovery has also increased since 2016 when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. While the Panel accepts that these requirements have become more onerous since 2016, FEI provides no evidence that these changing requirements have resulted in expenditures for which FEI has not received approval to recover from its customers nor is this risk perceived by investors to be higher for FEI than for other utilities.

With respect to FEI's submission that the BCUC's decision to consider that a more generic approach to deferral account financing treatment results in increased regulatory risk, no decision has yet been reached. The Panel agrees with BCOAPO that FEI (and FBC) will have a full opportunity to present their views in an open and transparent proceeding before the BCUC before any decision is made. Therefore, the Panel is not persuaded that FEI's overall regulatory risk has increased for its shareholder since 2016. **The Panel finds that FEI's regulatory risk is similar to what it was in 2016.**

Overall Business Risk

Interveners generally agree with FEI that its overall business risk has increased, but to a lesser degree than submitted by FEI. The CEC submits that FEI has a key risk in the Energy Transition, but that many of the other risks are overstated,[263] and recommends that the BCUC find FEI's business risk to be slightly higher than in

[263] The CEC Final Argument, p. 9.

2016.[264] RCIA submits that the perception of FEI risk appears to be higher today than it was in 2016, but states that FEI exaggerates the magnitude of such differences.[265] RCIA submits that given the absence of clear, objective evidence validating an absolute increase in business risk, RCIA opposes increasing FEI's equity thickness to the level requested by FEI.[266] BCOAPO agrees that FEI's business risk has increased since the FEI 2016 COC proceeding; however, it does not view FEI's business risk as having increased to the degree suggested by FEI.[267]

Given the findings discussed above associated with the changes in FEI's business risks to the shareholder, **the Panel finds that FEI's overall business risk has increased since 2016.** That increase is most significantly attributable to the increase in political risks associated with the Energy Transition and the cumulative effect of the perceived risks in Indigenous Rights and Engagement, energy price, and demand/market risks that could shift the risk to the shareholder if the utility is no longer viewed as an attractive investment by investors.

The Panel will address the impact of the increased business risk on FEI's capital structure and ROE, which are also influenced by factors beyond business risk, in Section 6.3 below (Overall Capital Structure and ROE).

4.3 FBC Business Risk

Unlike FEI, FBC's business risk was last assessed in the BCUC 2013 GCOC - Stage 2 proceeding.[268] In FortisBC's evidence, FBC provides an overview of its business risks across nine categories: four of which it considers to be of similar risk-level since 2013, with four categories considered to be of higher risk and only one considered to be lower.

FBC used similar categories as in the 2013 GCOC proceeding, other than the Indigenous Rights and Engagement risk factor. It was previously subsumed under political risk but has now been promoted to its own risk category. Additionally, the operating risk category has new risk factors: Project Resistance and Cybersecurity.[269] FBC summarizes its risk in the GCOC proceeding as "being similar to what was assessed in the 2013 Proceeding."[270] FortisBC prepared Table 10 below summarizing this risk assessment.

[264] The CEC Final Argument, p. 28.
[265] RCIA Final Argument, p. 31.
[266] RCIA Final Argument, p. 31
[267] BCOAPO Final Argument, p. 25
[268] Exhibit B1-8, p. 2
[269] Exhibit B1-8-1, Appendix B, p. 1.
[270] Ibid.

Table 10: Summary of FBC's Business Risk[271]

Business Risk Category	Risk Factor	Change in Risk Since 2013
Business Profile		**Similar**
	Type and Size of the Utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Lower**
	Energy policies and legislation	Lower
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher
Energy Price		**Similar**
	Power supply cost	Higher
	Competition with electricity	Higher
	Competition with natural gas	Lower
Demand/Market		**Similar**
	New technologies	Similar
	Wholesale and Industrial load	Similar
	Use per customer	Similar
	End-use market share	Lower
Energy Supply		**Similar**
	Security and reliability of supply	Similar
Operating		**Higher**
	Infrastructure integrity	Similar
	Unexpected events	Higher
	Project resistance	New (Higher)
	Cybersecurity	New (Higher)
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

Similar to FEI's business risk assessment above, the sections below review each business risk category and the positions of parties. To provide a comprehensive discussion, the Panel addresses parties' submissions and then provides overall findings and determinations on changes to FBC's business risks since the 2013 GCOC proceeding.

Business Profile

FortisBC states that FBC's structure as a fully integrated electric utility contributes to a higher risk profile than that of a distribution-only utility of a similar size - a situation exacerbated by a less diverse and relatively small customer base, concentrated in a small, but geographically diverse service area. Twenty-five percent of FBC's revenue and more than 30 percent of load are attributable to two customer classes, Industrial and Wholesale, a significant number of which can receive service from alternate sources of supply with only limited notice.

[271] Exhibit B1-8-1, Appendix B, p. 2–3.

Despite the slight increase in FBC's customer profile risk due to a higher share of the industrial sector being concentrated in forestry and cryptocurrency mining for the company's load and revenue profile, FBC has assessed its overall business profile risk to be similar to what was assessed in the 2013 GCOC proceeding.[272] FortisBC also acknowledges the Government/Education/Health sector has grown from 15 percent of the load in the top 20 customers in 2013 to 20 percent in 2020.[273]

Positions of Parties

BCOAPO submits the make-up of the revenue contribution from FBC's top industrial customers has changed and shifted from the more volatile forestry and technology sectors to the more stable Government/Health/Education sector. Overall, BCOAPO questions whether the risk associated with FBC's customer profile has materially increased (if at all) since 2013 and submits that FBC's business risk is similar to that in 2013.[274]

The CEC submits that it does not find the addition of a cryptocurrency customer to be an added risk but should instead be viewed as further diversification with the benefit of additional load. The CEC recommends that the BCUC find that the business profile risk is similar, or potentially lower than that from the 2013 GCOC proceeding due to the effects of the Energy Transition.[275]

In reply to the CEC, FBC states that there is ample evidence that the addition of the cryptocurrency customer raises the overall risk profile of FBC's Industrial load.[276]

ICG submits that there has been no increase in business risk so there should be no increase to the equity ratio.[277]

Similarly, RCIA submits that there is a lack of clear, objective evidence validating an increase in FBC's business risk.[278]

Economic Conditions

FortisBC states that economic conditions can affect the ability of utilities to attach new customers or retain existing customers and maintain throughput levels, in addition to affecting utility access to capital and cash flow from customers. FortisBC assesses that the record-high inflation rate, caused by government fiscal and monetary policy, and BC's challenges for long-term economic growth, point to higher risk. However, FortisBC states that economic conditions pose an elevated level of risk to smaller utilities because the smaller utilities have fewer abilities to diversify their operations and protect themselves against economic-driven volatility.[279]

[272] Exhibit B1-8-1, Appendix B, p. 3, Exhibit B1-8, p. 19.
[273] Exhibit B1-9, BCUC IR 33.9.
[274] BCOAPO Final Argument, pp. 29, 36.
[275] The CEC Final Argument p. 30.
[276] FortisBC Reply Argument, pp. 31–32.
[277] ICG Final Argument, p. 16.
[278] RCIA Final Argument, p. 31.
[279] Exhibit B1-8-1, Appendix 8, p. 13.

Positions of Parties

BCOAPO agrees that there is both greater uncertainties associated with the economic outlook for BC (and Canada), particularly in the short-term, and lower prospects for longer term growth.[280] However, the CEC submits that the overall economic conditions affecting the globe should be considered to be undiversifiable risks and should be provided with little to no weight in the BCUC's determinations regarding corporate risk.[281]

In reply to the CEC, FBC states that it is axiomatic that economic conditions can bring different risk to different enterprises and part of the focus of this proceeding is the effect of changed economic conditions on cost of capital for utilities.[282]

Political

FortisBC defines political risk as the potential for governments or other stakeholders to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, and safety regulations.[283] FortisBC states that the government push for electrification of the BC economy as the preferred option to reduce emissions is providing FBC with both opportunities and challenges. Namely, government policies to electrify the building and transportation sectors can increase FBC's market share and load; however, rapid policy-driven customer migration from fossil fuels to electricity presents operational challenges for FBC which has limited resources in a small geographical service territory.[284]

Therefore, FortisBC states that over-reliance of government policy on electrification as the only solution to the climate change crisis can lead to increased costs to FBC and its customers.[285] In addition, FortisBC states that the government's ability to subsidize BC Hydro customers is not a path open to FBC. BC Hydro is the primary beneficiary from FEI's challenges in the Energy Transition.[286] Overall, however, FBC assesses that its political risk is lower than what was assessed in the 2013 GCOC proceeding.[287]

Positions of Parties

BCOAPO and the CEC submit that FBC's political risk is lower now than in 2013 due to the Energy Transition and the associated policies that favour electrification.[288] However, the CEC disagrees that BC Hydro is the 'Primary Beneficiary of Fuel Switching' from FEI, as FBC is generally not in competition with BC Hydro. The CEC finds it incongruent that FortisBC is concluding that rapid growth presents risk while also stating that the lack of growth potential due to limited area size is a risk and recommends that little weight be assigned to these arguments.[289]

[280] BCOAPO Final Argument, p. 14, 29.
[281] The CEC Final Argument, p. 31.
[282] FortisBC Reply Argument, p. 32.
[283] Exhibit B1-8-1, Appendix B, p. 14.
[284] Exhibit B1-8, p. 18.
[285] Exhibit B1-8-1, Appendix B, pp. 14–15.
[286] Exhibit B1-8, p. 18; Transcript Volume 5A, p. 706.
[287] Exhibit B1-8, p. 18.
[288] BCOAPO Final Argument, p. 29, The CEC Final Argument, pp. 30–31.
[289] The CEC Final Argument, p. 31.

ICG states that the Energy Transition that limits the future growth prospects of FEI is mirrored in expanded FBC growth prospects. That is, the fundamental changes that are occurring in the energy sector for FEI are mirrored in fundamental changes to the business risks of FBC.[290]

In reply to the CEC, FortisBC states that FBC points out the following: (i) that BC Hydro is the primary beneficiary of fuel switching from FEI, to place the impact of fuel switching policy in its proper context, as BC Hydro has greater overlap between its service territory with that of FEI; (ii) municipal fuel switching policy is mostly being implemented in BC Hydro's service territory rather than FBC's; and (iii) heat pumps are more competitive in the Lower Mainland and Vancouver Island than in FBC's service territory. FortisBC also submits that the CEC's political risk argument overlooks how rapid growth from the Energy Transition could present risk; FBC has limited opportunity to expand its service territory, as it is surrounded by BC Hydro territory and growth in FBC's customer base and accelerated electrification in its existing service area could pose threats to grid integrity.[291]

In reply to ICG, FortisBC notes that ICG appears to base its position on the incorrect proposition that FBC's business risk and FEI's business risk is a zero-sum game. FortisBC submits that business risk is not limited to a consideration of the give-and-take growth prospects of natural gas versus electric utilities. FortisBC states that FBC faces higher risk in some areas and accelerated growth comes with its own set of risks to FBC.[292]

Indigenous Rights and Engagement

FBC defines the Indigenous Rights and Engagement risk as the potential for governments to negatively impact utility operations through policy, legislation and/or regulations concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. FBC faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of the BCUC's 2013 GCOC proceeding. This elevated risk is based on the evolving nature of the Crown's relationship with Indigenous groups, developments in reconciliation in Canada, significantly increased expectations among Indigenous groups, and legal claims related to Aboriginal rights and title.[293]

Positions of Parties

BCOAPO submits that, while Indigenous Rights and Engagement risk has increased since 2013, FBC appears to be effectively managing the risk such that it has not impacted/will not impact FBC's business to the extent suggested by FBC's evidence.[294]

The CEC submits that the risk in this category is significantly lower than that for FEI in that FBC's land area is confined and there are fewer Indigenous groups affected by FBC operations. The CEC submits that the risk to FBC related to Indigenous Rights and Engagement is largely the same as it was in 2013. The CEC recommends that the BCUC find FBC's Indigenous Rights and Engagement risk to be similar as in the 2013 GCOC proceeding.[295]

[290] ICG Final Argument, p. 4.
[291] FortisBC Reply Argument, pp. 32–33.
[292] FortisBC Reply Argument, p. 31.
[293] Exhibit B1-8-1, Appendix B, p. 16.
[294] BCOAPO Final Argument, p. 30.
[295] The CEC Final Argument, p. 32.

In reply to the CEC, FortisBC submits that FBC's Indigenous rights and engagement risk must be viewed considering its small size — the fact that FBC's service territory engages with fewer Indigenous traditional territories than FEI does not work to lower FBC's risk. The potential impacts of FBC's operations on Indigenous communities are no less meaningful because its operations have the potential to affect fewer Indigenous groups.[296]

Energy Price

FortisBC states that the analysis of energy price risk focuses on power supply factors placing upward pressure on FBC's rates and on the competitiveness of FBC's rates. While the risks related to the BC Hydro Power Purchase Agreement rate increases remain similar to 2013, FortisBC notes that market price volatility and purchase agreements contract rate risk have increased.[297] The level of utility rates can influence consumers' energy choices. Specifically, higher electricity rates in FBC's service territory can hinder FBC's ability to attract new customers (particularly new industrial and larger commercial customers). In addition, higher electricity rates can discourage residential customers from using electricity for space heating and water heating which can affect FBC's market share and UPC.[298]

While FortisBC acknowledges that FBC's rate competitiveness risk compared to BC Hydro is similar to what it was in 2013, FortisBC states it is trending higher. In addition, FBC's rate competitiveness relative to natural gas is similar to that in 2013; however, given expected increases to gas and carbon tax rates, FBC expects its rate competitiveness to improve.[299]

Positions of Parties

BCOAPO submits that the price risk is not as great as suggested by FBC but accepts FBC's overall assessment that its overall price/rate competitiveness risk is similar to that assessed in the 2013 GCOC proceeding.[300] The CEC recommends that the BCUC find the energy price risk to be similar to its finding in the 2013 GCOC proceeding and potentially lowering as new technologies continue to provide benefits.[301] ICG submits that power supply costs may have increased, but have not increased FBC's business risks, as the number of customers that can choose between BC Hydro and FBC is not material and is limited to a very small geographical area, and for that reason, competition with electricity should not be considered a significant risk.[302]

In reply, FortisBC only acknowledges that BCOAPO agrees and, in response to the CEC, submits that new technologies, like wind and solar energy generation resources, do not provide reliable capacity and as such, declines in the cost of the energy produce simply shifting the risk to capacity. The benefits of policies favouring electricity are offset at present by other factors.[303] FortisBC does not address ICG's submissions in its reply argument.

[296] FortisBC Reply Argument, pp. 33–34.
[297] Exhibit B1-8, p.18.
[298] Exhibit B1-8-1, Appendix B, p. 17.
[299] Exhibit B1-8, p. 19.
[300] BCOAPO Final Argument, pp. 30–31.
[301] The CEC Final Argument, p. 33.
[302] ICG Final Argument, pp. 5–6.
[303] FortisBC Reply Argument, p. 34.

Demand/Market

Demand risk, also referred to as market risk, generally refers to the risk arising from changes in consumer behaviour and the markets to which the utility has exposure.[304] FortisBC states that emerging technologies can provide challenges for FBC, as alternative sources of energy such as home solar generation can reduce the demand, while conversely new load requirements such as electric vehicle (EV) charging can increase the load requirements of FBC.

Both situations create risks for higher costs, as well as risks to grid integrity, including managing the timing of load on the system to avoid peak demand impacts. FortisBC also states that FBC continues to face demand risk in its wholesale and industrial customer segments because these customers are able to take service from competing utilities within the province, build generation to serve some or all of their load, or purchase electricity from the open market.[305] However, FortisBC states that no wholesale or industrial customers have left FBC, nor have they expressed an intent to leave FBC.[306]

In addition, FortisBC states that both building generation and arranging for third-party supply can be complicated and retail access to the open market for electricity purchases is not available.[307] Finally, FortisBC states that compared to 2013, FBC's residential and commercial UPC values have been on a downward trajectory while Industrial UPC has increased.[308] However, FBC has not included EV load growth in the declining residential UPC.[309] FBC expects an increase in its electricity thermal market share relative to natural gas and other fuel sources over the longer term as heat pump penetration increases, thereby reducing this aspect of FBC's market share risk from 2013 and current levels. Overall, FBC views its demand risk as similar to what was assessed in the 2013 GCOC proceeding.[310]

Positions of Parties

BCOAPO submits that there is limited risk to FBC of losing load from either wholesale or industrial customers seeking service from an alternative supplier or self generation. Also, BCOAPO notes that FBC has not taken the longer-term impact of EV load and heat pump penetration increases on the Residential UPC into account in its risk assessment. Finally, BCOAPO notes that the discussion of FBC's demand/market risk does not make any specific reference to the favourable trend of customers' energy choices trending towards more environmental and affordable sources of supply which will favor electricity. Overall, BCOAPO submits that the demand/market risk faced by FBC has likely decreased as compared to that in 2013.[311]

The CEC submits that there are always negatives and positives to be found with every type of change, and they should not be provided with weight unless they are likely to have a material impact. The CEC submits that in this case, the ability to meet peak load can reasonably be expected to be met with new infrastructure or demand

[304] Exhibit B1-8-1, Appendix B, p. 25.
[305] Exhibit B1-8, p. 19.
[306] Exhibit B1-9, BCUC IR 32.1.
[307] Ibid., BCUC IRs 32.1, 33.4.
[308] Exhibit B1-8, p. 19.
[309] Exhibit B1-10, BCOAPO IR 15.3.1.
[310] Exhibit B1-8, p. 19.
[311] BCOAPO Final Argument, p. 32.

side management as approved by the BCUC. The CEC recommends that the BCUC find the demand/market risk for FBC to be lower overall.[312]

In reply to BCOAPO and the CEC, FortisBC submits that FBC's overall demand/market risk is similar to what it was during the 2013 GCOC proceeding and stands by its final submissions.[313]

Energy Supply

FortisBC states, as in 2013, FBC's power supply comes from three sources:

i. Its own hydro generating plants - FortisBC describes the failure of a plant generating unit would result in the need to acquire replacement power, which may not be available due to either lack of available supply or available transmission, or may only be available on the open market at a significantly increased cost;

ii. Long-term contracts with suppliers - As long-term supply contract agreements expire, FBC states that there is no guarantee that it will be able to renew them, or that they could be renewed at a similar cost; and

iii. The wholesale market - FBC's dependence on the availability of third-party transmission capacity to meet demand increases the risk that FBC is not able to access cost-effective market supply.

FortisBC states that there is risk associated with each supply, but the level of risk remains similar to that in 2013.[314]

Positions of Parties

BCOAPO has no issues with FBC's assessment of its energy supply risk and the CEC agrees that the energy supply risk remains similar to that in the 2013 GCOC proceeding. However, the CEC recommends that the BCUC provide moderate weight to this category.[315]

FBC did not comment in its reply argument on the energy supply risk.

Operating

FortisBC states that operating risk is defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather.[316] FortisBC explains that the primary operating risks associated with FBC's generation and infrastructure assets are related to the age and cost to maintain and upgrade these assets. FBC is exposed to additional risk from its transmission and distribution assets which are primarily above ground and the potential for increases in unpredictable extreme weather events, such as wildfires and flooding, to compromise the integrity of these assets.

[312] The CEC Final Argument, p. 33.
[313] FortisBC Reply Argument, p. 34.
[314] Exhibit B-8-1, Appendix B, pp. 41–42.
[315] BCOAPO Final Argument, p.34, The CEC Final Argument, p. 34.
[316] Exhibit B1-8-1, Appendix B, p. 43.

Other unexpected events, such as the COVID-19 pandemic, disrupt supply chains and cause delays in FBC's capital work, which impacts its ability to maintain and operate its system. Additionally, FBC has experienced an increase in incidences of cyberattacks and expects to see increased resistance to projects, which will lead to higher risks to execute projects on time at the lowest reasonable cost. Therefore, FBC assesses its operating risk as being higher than in 2013.[317]

Positions of Parties

BCOAPO accepts FBC's assessment that its operating risk has increased since 2013 based on the factors cited by FBC.[318] However, the CEC recommends that the BCUC find the operating risk to be similar to that in 2013.[319] The CEC does not consider the age and cost to maintain the generation infrastructure assets as a higher risk for FortisBC and considers it at least the same as, or lower than previously, as ratepayers pay for necessary upgrades. The CEC submits that there may be some degree of selection or framing bias as FBC does not address distribution or other infrastructure except with respect to 'Unexpected Events'. While the CEC agrees that there is an increase in unexpected events, such as extreme weather affecting transmission and distribution, the CEC notes that FBC has additional advanced metering infrastructure embedded in its network which can assist with mitigating risk to customers.

Regarding project resistance, the CEC submits that the utility has the obligation, and the capability, to plan for and seek approval for appropriate timing and costing so that it can continue to execute projects cost effectively and on time and recommends that little to no weight be assigned to FBC's arguments. The CEC submits that cyberattacks are on the rise generally and should be considered as a non-diversifiable risk.[320]

In reply, FortisBC states that FBC's risk assessment is post-mitigation, and while risks such as cybersecurity may broadly impact other entities, the risk is more acute for utilities than many other enterprises. The increased threat of cybersecurity attacks may have serious repercussions. In addition, FortisBC also notes that it has provided ample evidence of serious and increasingly frequent extreme weather events, which cause lengthy outage periods for customers and require resource-intensive transmission and distribution infrastructure rebuilds. FortisBC submits that the potential costs associated with these increasing risks may prevent FBC from earning its allowed return. [321]

Regulatory

FortisBC defines regulatory risk as the degree to which FBC, as a regulated public utility, is dependent on regulators for timely and objective approvals that directly impact its ability to earn a fair return on and of capital. FortisBC has assessed FBC's overall regulatory risk as higher than what was assessed in the 2013 GCOC proceeding, with certain risk factors increasing and others being similar. FortisBC states that regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are

[317] Exhibit B1-8, p. 20.
[318] BCOAPO Final Argument, p.34.
[319] The CEC Final Argument, p. 35.
[320] The CEC Final Argument, pp. 34–35.
[321] Fortis Reply Argument, p. 36.

set at a level that does not provide FBC with an opportunity to earn its fair return, or that necessary investments are not approved.

FortisBC states that there is uncertainty caused by the BCUC's decision to consider a more generic approach to deferral account financing treatment. FortisBC also notes that the risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 GCOC proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title.[322]

In addition, FortisBC states that the failure to comply with the adopted BC Mandatory Reliability Standards (MRS) requirements can lead to the BCUC imposing administrative penalties against FBC. Compared to 2013, the scope and comprehensiveness of the BC MRS requirements have increased. While FBC strives to comply with the BC MRS requirements, there is always a risk that non-compliance may occur.[323]

Positions of Parties

BCOAPO submits that MRS requirements do not give rise to an increase in regulatory risk relative to 2013, as FBC is familiar with the requirements. BCOAPO submits that FBC's regulatory risk remains relatively unchanged from that in the 2013 GCOC proceeding.[324]

In reply, FortisBC does not address BCOAPO's submission on MRS.

The CEC does not view FBC's additional concerns to be significant and notes that the BCUC can approve additional funding to cope with MRS requirements. Therefore, the CEC also applies its views on regulatory risk for FEI to FBC and recommends that the BCUC find FBC's regulatory environment to be favourable.[325]

In reply to the CEC, FortisBC does not address the CEC's submission on MRS and repeats the same arguments for FBC as it did for FEI.[326]

ICG submits that there is no evidence to support FBC's conclusion that regulatory uncertainty and lag have increased.[327] In reply to ICG, FortisBC states that it provided evidence of these business risks in its evidence, in numerous responses to information requests, and at the oral hearing. [328]

Panel Determination

Similar to its approach with the assessment of FEI's business risks, the Panel focuses on how FBC's business risk categories have changed since 2013 from a shareholder and investor perspective. Thus, we do not focus on business profile, energy price and supply risk categories, as we agree that all of these are similar to 2013 and no parties raised any material issue with that assessment. We address where FBC has noted changes in risk and

[322] Exhibit B1-8, p. 20.
[323] Exhibit B1-8-1, Appendix B, p. 55.
[324] BCOAPO Final Argument, p. 35.
[325] The CEC Final Argument, pp. 27, 35.
[326] FortisBC Reply Argument, pp.27–28, 37.
[327] ICG Final Argument, p. 5.
[328] FortisBC Reply Argument, p. 37.

discuss whether we agree with the changes and whether they affect the risk, real or perceived, to the shareholder and investor rather than to the ratepayer. We begin our analysis with an assessment of FBC's economic conditions risk below.

Economic Conditions

FBC assesses that its economic conditions risk is higher than in 2013 due to record-high inflation rates caused by government fiscal and monetary policy, and BC's challenges for long-term economic growth. The Panel notes that FBC did not provide evidence that this risk is perceived differently by investors for FBC than for other utilities. Additionally, the Panel finds no evidence to support FBC's submission that this risk will affect FBC's ability to access capital or impact its cash flow from customers, as increased cost resulting from inflations are recoverable from ratepayers.

The Panel is not persuaded that the present short-term economic conditions will materially affect the ability of FBC to attach new customers or retain existing customers and maintain throughput levels. As the costs are recoverable from ratepayers, and investors do not perceive this risk higher for FBC than a comparable utility, **the Panel finds that FBC's economic conditions risk to the shareholder and investor to be similar to what it was in 2013.**

Political

FBC assesses its political risk as lower than what was assessed in 2013 and the Panel agrees. The Panel notes that FBC, as well as BCOAPO, the CEC and ICG all submit that the risk is lower than in 2013. The Panel also notes that ICG submitted that "the Energy Transition that limits on the future growth prospects of FEI are mirrored in expanded FBC growth prospects".

The Panel agrees that business risk is not limited to a consideration of the give-and-take growth prospects of natural gas versus electric utilities. We accept that rapid growth from the Energy Transition presents opportunities for FBC, both real and perceived. However, it could also present risks that it will not be able to effectively deal with such rapid growth. The Panel puts more weight on growth opportunities because current policies and investor perceptions favour FBC as an electric utility and opportunities in most cases come with certain degree of risk. Therefore, on balance, **the Panel finds that FBC's political risk to the shareholder and investor is lower than it was in 2013.**

Indigenous Rights and Engagement

FBC assesses that it faces an elevated level of risk related to relationships with Indigenous groups in BC compared to 2013. We do not disagree but we find this risk is mitigated, at least in part, by the likely recovery of the costs associated with project delays and increased engagement from ratepayers through rates.
The Panel is persuaded that the potential and perceived impacts of FBC's operations on Indigenous communities are no less meaningful to those of FEI merely because its operations have the potential to affect fewer Indigenous groups.

In our view, while this risk is largely borne by ratepayers, this issue is likely to impact investors' perception of risk. However, as with many risks, the risks associated with Indigenous Engagement and Consultation also comes with opportunity to engage with First Nations and we encourage FBC to seek out those opportunities.

Accordingly, **the Panel finds that FBC's Indigenous Rights and Engagement risk to the shareholder is somewhat higher than it was in 2013**.

Demand/Market

FBC assesses its demand/market risk as similar to what was assessed in 2013. However, the Panel notes that BCOAPO and the CEC submit that demand/market risk is lower than it was in 2013. BCOAPO submits that FBC has not taken the longer-term impact of EV load and heat pump penetration increases on the Residential UPC into account in its risk assessment or makes any specific reference to its customer's energy choices trending towards those favouring electricity. The Panel considers that emerging technologies can also provide challenges for FBC, as alternative sources of energy such as home solar generation can reduce the demand on new load requirements, thereby offsetting some of the reduced risk associated with potential EV and heat pump load. The Panel also notes that any cost differences as a result of load will be absorbed by customers through rates.

Although the CEC submits that FBC's ability to meet peak load can reasonably be expected to be met with new infrastructure or demand side management as approved by the BCUC, the Panel considers this does not result in a reduction of demand/market risk for FBC, as the associated costs would have always been recoverable through rates. Further, the Panel agrees with the CEC that there are always negatives and positives with every type of change, and such changes should not be provided with weight unless they are likely to have a material impact or perceived to have an impact. In this case, the Panel finds that overall, the negative and positive impacts offset each other with minimal impact to the shareholder, in addition, there has been no indication that investors perceive this risk as lower than in previous years or less than another utility. Accordingly, **the Panel finds that FBC's demand/market risk to the shareholder is similar to what it was in 2013.**

Operating

FBC assesses its operating risk as being higher than in 2013. FBC submits that it is exposed to additional risk from the potential for increases in unpredictable extreme weather events such as wildfires and flooding which compromise the integrity of its transmission and distribution assets. BCOAPO agrees with FBC. The CEC, however, submits that this risk is similar to that of 2013. ICG submits that no weight should be given to this risk category in determining the appropriate capital structure for FBC, implying that the risk is similar to that of 2013.

FBC submits that the primary operating risks associated with FBC's generation and infrastructure assets are related to the age of these assets and their maintenance and upgrade costs. FBC also submits that other unexpected events, such as the COVID-19 pandemic, disrupt supply chains, cause delays in FBC's capital work, and impact its ability to maintain and operate its system. Similarly, FBC states that incidences of increased cyberattacks represent an increase to FBC's operating risk. The Panel notes that FBC did not present evidence that demonstrates that investors view these risks differently for FBC than for other utilities, nor did FBC provide evidence demonstrating that its ability to maintain and operate its system has been compromised, nor has it been unable to recover its incurred expenditures needed to address these operating risks. Accordingly, the Panel

is not persuaded that FBC's operating risk has increased since 2013, and **the Panel finds that FBC's operating risk is similar to what it was in 2013.**

Regulatory

FBC assesses its overall regulatory risk as higher than what was assessed in 2013. FBC submits that risk has increased as a result of regulatory uncertainty, regulatory lag, and changing MRS requirements. BCOAPO, the CEC and ICG all submit that the risk is similar to what it was in 2013.

FBC submits that regulatory uncertainty gives rise to the risk that the allowed return or rates may not meet the Fair Return Standard, or that necessary investments are not approved. FBC provided no evidence that perceived regulatory uncertainty has led to its allowed return not meeting the Fair Return Standard, or rates being set at a level that does not provide FBC an opportunity to earn its allowed return. Similarly, FBC provided no evidence where recovery has been disallowed for approved investments. Finally, FBC provided no evidence that the likelihood of these outcomes occurring is higher today than in 2013, nor is the risk of these outcomes occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that FBC's regulatory risk due to regulatory uncertainty has increased.

FBC submits that risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 GCOC proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. While the Panel accepts that these requirements have become more onerous since 2013, the Panel notes that FBC provided no evidence that these changing requirements have resulted in expenditures for which FBC has not received approval to recover the costs from its customers. Nor has FBC provided evidence that the likelihood of this occurring is higher today than in 2013, nor is the risk of this occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that regulatory risk due to regulatory lag and ultimate cost recovery has increased.

FBC submits that the risk associated with MRS requirements has increased. FBC submits that MRS requirements have increased since 2013 and that there is always a risk that non-compliance with MRS may occur, which may lead to administrative penalties. The Panel accepts that MRS requirements have increased since 2013 and that non-compliance may lead to the imposition of administrative penalties. However, the Panel notes that the BCUC has not disallowed recovery of costs from customers associated with FBC meeting its MRS requirements, nor has FBC provided evidence that the likelihood of this occurring is higher today than in 2013, nor is the risk of this occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that regulatory risk due to MRS requirements has increased. Thus**, the Panel finds the FBC's overall regulatory risk to the shareholder and investor to be similar to what it was in 2013.**

Overall Business Risk

While some of FBC's business risks have increased to a degree, these have been offset by reductions in other risk categories. The Panel notes that the CEC submits that overall, FBC's business risk is slightly lower than it was in 2013 due to the effects of the Energy Transition.[329] However, the CEC does not submit that this should result in a reduction to FBC's equity component. Other interveners submit that FBC's overall business risk is similar to that

[329] The CEC Final Argument, p. 30.

of 2013. RCIA submits that there is "… the absence of clear, objective evidence validating an absolute increase in business risk,"[330] and ICG submits that "[i]n the current circumstance of FBC, there has been no increase in business risk so there should be no increase to the equity ratio."[331] Finally, BCOAPO submits that "… the BCUC should conclude that, on an overall basis, FBC's business risk is similar to that of the 2013 GCOC proceeding";[332] however, BCOAPO also submits that FBC's business risk would be lower relative to that of other Canadian and US electric utilities[333].

Given the findings associated with each of the business risk categories, **the Panel finds that FBC's business risk overall has not changed materially since 2013.** This is attributable to most of the risk to the shareholder remaining similar to 2013 and the decrease in political risks associated with the Energy Transition compared to the perceived increase in risk for Indigenous Rights and Engagement, resulting in no net change in FBC's attractiveness as an investment to investors. The Panel will address the impact of this overall assessment of FBC's business risk on its capital structure and ROE, which are influenced by factors beyond business risk, in Section 6.3 below (Overall Capital Structure and ROE).

Having addressed the changes in business risks for FEI and FBC, we now review the various financial models used by the experts in assessing an appropriate ROE for the two utilities.

5.0 FINANCIAL MODELS

5.1 Rationale for the Use of Financial Models

Regulators rely on financial models because the cost of equity for a regulated utility cannot be observed. All models are simplifications of reality, using simplifying assumptions and as such, they are all subject to varying degrees of criticism.[334] Quantitative models produce a range of reasonable results from which the ROE is selected. Mr. Coyne states that the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' forward-looking views of the financial markets in general and the subject company (in the context of the proxy group) in particular.[335]

Dr. Lesser explains that models that are used by regulators to set the cost of capital for regulated utilities should possess certain characteristics: 1) a sound basis in financial theory; 2) model transparency; and 3) minimal reliance on subjective factor. In addition, they shouldn't be systematically biased.[336]

Dr. Lesser further explains that methodologies used to estimate the allowed return on equity for a regulated utility should be consistent with accepted financial theory and basic economics, namely, that the allowed return reflects the opportunity cost of capital. Non-market approach, such as the Comparable Earnings approach is

[330] RCIA Final Argument, p. 31.
[331] ICG Final Argument, p. 16.
[332] BCOAPO Final Argument, p. 36.
[333] Ibid.
[334] Exhibit A2-3, p. 22.
[335] Exhibit B1-8-1, Appendix C, p. 45.
[336] Exhibit A2-3, p. 22.

unlikely to reflect the opportunity cost of capital, as it bases allowed returns on accounting measures which can be influenced by specific events or differences in accounting practices.[337]

Model transparency reflects two important dimensions: understandability and replicability and requires, in Dr. Lesser's view, the reliance on data that is publicly available or available at a low cost.[338] Finally, all models involve some degree of subjectivity owing to the choices of inputs but Dr. Lesser explains that subjectivity can be reduced to some extent when regulators specify the methodologies and the inputs that should be used to implement those methodologies beforehand. For example, adjusting model results to account for perceived anomalous capital market conditions without any underlying basis in financial theory and no empirical support is subjective. He recommends that regulators question these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with "reasonable decision-making".[339]

Mr. Coyne explains that no model can exactly pinpoint the correct return on equity, but rather each model brings its own perspective and set of inputs that inform the estimate of ROE and as such, no model should be relied upon individually without corroboration from other approaches. Mr. Coyne also notes that using multiple models mitigates the inherent imperfections in each of the models and there is additional value in using multiple models during "volatile market conditions, such as those experienced over the last decade." Furthermore, analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.[340]

In its 2016 Decision, the BCUC acknowledged the need to use multiple methodologies in determining a fair return on equity, stating:

> The Panel notes that while there are some differing perspectives among the experts and parties, their views are generally consistent with the Brattle Group Report's finding that decisions should be informed by use of multiple financial models and other indicators of investor expectations where appropriate. The Panel agrees it should consider the "totality of information resulting from applying multiple tests." The Panel also agrees it should consider all of the information from the application of the models presented, as well as other indicators of the fair ROE and should apply its own judgment to determine the appropriate ROE.[341]

Mr. Coyne presented the results of four models: multi-stage DCF, constant growth DCF, CAPM and Risk Premium. His recommendations ultimately reflect the average output of multi-stage DCF and CAPM models, which is the approach adopted in the 2016 Decision.[342] Mr. Coyne supports the BCUC's previous approach of using multiple methodologies and believes it is appropriate to place equal weight on the results of the CAPM and Multi-Stage DCF model. But he also notes that FERC includes the Risk Premium Model, in addition to the CAPM and Two-Stage DCF models, to establish the return for electric transmission companies, and gives equal weight to the results of those three approaches. Mr. Coyne further points out that in volatile market conditions, there is additional value in using multiple models. All models have their strengths and weaknesses, so relying on

[337] Exhibit A2-3, p. 23.
[338] Ibid.
[339] Ibid., pp. 24–25.
[340] Exhibit B1-8-1, Appendix C, pp. 45–46, Exhibit B1-9, BCUC IR 44.3.
[341] 2016 Decision, p. 47.
[342] FortisBC Final Argument, p. 136.

an equal weighting of two (or more) improves both the reliability of the estimate and the confidence that stakeholders can place in the results.[343]

FortisBC states that Mr. Coyne and Dr. Lesser agree on the importance of using multiple models to estimate a utility's cost of equity and submits that, ultimately, the BCUC should consider the result of all four models used by Mr. Coyne, even if greater weight is applied to the CAPM and Multi-Stage DCF results.[344]

As BCOAPO observes, the evidence is clear that, despite the numerous points upon which Mr. Coyne and Dr. Lesser disagree, they do both agree that ROE estimates should be based on the use of multiple models. BCOAPO supports this premise as a reasonable response to a challenging issue.[345]

The Panel will discuss its views of each model in the next sub-sections, reviewing in turn the CAPM, the DCF methodology, and the Risk Premium Model. The Panel will then determine the various weightings to be attributed to each model in Section 6.3.

Briefly, the CAPM is based on the long-observed relationship between non-diversifiable risk and expected return, the DCF methodology is based on the premise that today's stock price represents investors' expectations regarding future cash flows from holding that stock in terms of dividends and price appreciation, and the Risk Premium Model is based on the premise that common equity capital is riskier than debt and, therefore, equity investors require a greater return than would bondholders.

5.2 Capital Asset Pricing Model

The CAPM is commonly used in business valuation and regulatory jurisdictions to estimate ROE. The CAPM financial model estimates the expected return of an investment or security based on its riskiness relative to the rest of the market. The BCUC has recognized the use of the CAPM in prior cost of capital decisions.[346]

The CAPM is based on the relationship between the required return of a security and the systematic risk of that security and is defined by the following equation:

$$K_e = rf + \beta(rm - rf) \qquad (1)$$

Where:

K_e = the required ROE for a given security;

rf = the risk-free rate of return;

β = Beta is the systematic risk of an individual security;

rm = the required return for the market as a whole; and

(rm – rf) = Market risk premium (MRP) is the premium that equity investors demand to compensate them for the extra risk they accept

[343] Exhibit B1-9, BCUC IR 44.3.

[344] FortisBC Final Argument, p. 136.

[345] BCOAPO Final Argument, p. 37.

[346] 2013 Decision, 2016 Decision.

Dr. Lesser states that the CAPM is the most used approach for estimating allowed ROE values. In his view, the model is understandable, transparent, based on sound financial theory, and there are readily available data with which to develop CAPM estimates. He explains that the assumptions used in deriving estimates for each of the three CAPM components can have a significant impact on the ROE result and that key empirical issues for regulators to consider when using the CAPM are as follows:

a) What risk-free rate (*rf*) should be used;

b) Whether to use raw or adjusted beta and to adjust for differences in leverage to reflect differences in capital structure;

c) How to determine the expected market return (*rm*) and whether the market-risk premium (*rm – rf*) should be historical or forward-looking;[347] and

d) Whether a size premium is appropriate.[348]

5.2.1 Risk-Free Rate

The risk-free rate of return is a theoretical return that carries no risk. Dr. Lesser points out that even though a truly "risk-free" asset does not exist, most regulators rely on long-term government bond yields as the risk-free rate when using the CAPM to set the allowed ROE because determining an allowed ROE is a long-term exercise and the yield on long-term government bonds is the closest thing to the hypothetical risk-free rate.[349]

Mr. Coyne and Dr. Lesser agree that the yield on long-term government bonds is the appropriate basis to estimate the risk-free rate of return. They also agree that using a 30-year horizon is appropriate.[350] However, one area of disagreement is Dr. Lesser's use of current average government bond yields instead of Mr. Coyne's use of forecast bond yields.[351]

Mr. Coyne states that since the bond yields in December 2021 remain near historical lows, adjustments are necessary to better reflect forward-looking circumstances because investors are factoring higher interest rates into their longer-term expectations and required returns. He relies on the 30-year forecast bond yields for his analysis, calculated as the 2022–2024 average *Consensus Economics* forecast of the Canadian 10-year government bond, later updated to 2023–2025, plus the average spread between 10-year and 30-year government debt. Mr. Coyne explains that the use of a forecast yield is appropriate, as it provides a forward-looking view of the cost of equity and accounts for the market's expectations for a return to more normal (higher) interest rates.[352] Also, Mr. Coyne emphasizes that it is a longstanding regulatory practice in Canada to base the cost of capital on an expectation of the bond yield using some sort of forecast.[353]

Dr. Lesser prefers using current average government bond yields. In his view, based on the Efficient Market Hypothesis, the current yield already reflects investors' collective expectations about interest rates such that using forecasts would amount to a double-counting of expectations. Also, he remarks that low interest rates

[347] Exhibit A2-3, p. 58.
[348] Ibid., p. 59.
[349] Exhibit A2-3, p. 45.
[350] Exhibit B1-8-1, Appendix C, p. 56, Exhibit A2-3, p. 46.
[351] Exhibit B1-21, p. 5.
[352] Exhibit B1-8-1, Appendix C, p. 56.
[353] Transcript Volume 3, p. 184, Line 13–16.

induced by government actions do reflect the true cost of capital and argues that the opposite begs the question of what is the "true" cost of capital.[354]

Dr. Lesser relies on both the 30-day and 90-day average bond yield. Dr. Lesser states that he often will use a one-month average (30-days) because interest rates tend to be less volatile than stock prices.[355] However, he also notes that it would be reasonable to use a slightly longer period, between one and three months (i.e. 90 days).[356] Dr. Lesser notes that, while he supports using the current yield, the decision on the time period is subjective on the best way to approach it, stating that "it may make very little difference" and there is no "optimal averaging period".[357]

Mr. Coyne disagrees and reiterates that under current market circumstances (around June 2022), when interest rates are changing rapidly as central banks in the US and Canada normalize monetary policy in response to higher than expected inflation, the use of current average yield tends to understate the level of interest rates during the period for which the cost of equity is being set.[358] During the oral hearing, Mr. Coyne explained:

> MR. COYNE: But case in point going back to December when we put our data together, our forecast bond yield for the U.S. long term is 2.91 percent and for Canada it was 2.58 percent. In October [2022], the actual for Canada is 3.374 and the actual for October in the U.S. is 4.04. So those numbers are already over a percent higher than what we had predicted -- what Consensus Economics had predicted back then. They had the trend right, but not the magnitude right of just how much it was going to increase. Had I adopted Dr. Lesser's approach back in December of 2021, I would have used a Canadian bond yield of only 1.76 percent and a U.S. bond yield of 1.84 percent. And as I said, they're now 4 percent in the U.S. and 3.3 percent in Canada. So it clearly would have underestimated what's occurred in the market for government bond yields, even the forecast underestimated what's occurred.[359]

Reflecting the Panel's determination that it should be using the October 2022 data to inform the establishment of an appropriate ROE, the following table presents the October 2022 risk-free rates resulting from the two experts' respective approaches.

Table 11: Summary of Risk-Free Rates[360]

Canada			
As of	**Forecast**	**Current 30-day**	**Current 90-day**
October 2022	3.21%	3.27%	3.09%
U.S.			
As of	**Forecast**	**Current 30-day**	**Current 90-day**
October 2022	3.50%	3.92%	3.43%

[354] Exhibit A2-3, p. 46.

[355] Transcript Volume 3, p. 182, Lines 5–8.

[356] Ibid., p. 201, Lines 22–26 to p. 202, Lines 1–9.

[357] Ibid., p. 201, Lines 22–26 to p. 202, Lines 1–9.

[358] Exhibit B1-21, p. 14.

[359] Transcript Volume 3, p. 184, Lines 17–26 to p.185, Lines 1–8.

[360] Information in the table has been compiled from Exhibit B1-8-1-2, A.2 Gas and Electric attachments for Forecast (Canada and US), Exhibit B1-8-1-2, B.6 Gas and Electric attachments for Current 30-day (Canada and US), Exhibit B1-8-1-2, B.7 Gas and Electric attachments for Current 90-day (Canada and US).

FortisBC submits that the risk-free rate should be determined using forecast bond yields, not current government bond yields. FortisBC states that the BCUC should find that Mr. Coyne's approach is most reasonable since it best reflects how investors make decisions. FortisBC refers to Mr. Coyne's statement that the entire forecasting industry is predicated on investors using forecasts, rather than just the current price, in making investment decisions. FortisBC also points out that Mr. Coyne's approach is consistent with the logic underpinning automatic adjustment mechanisms (AAMs) approved by Canadian regulators, including the previously BCUC-approved AAM, which has long been calibrated to forecast bond yields rather than current bond yields.[361]

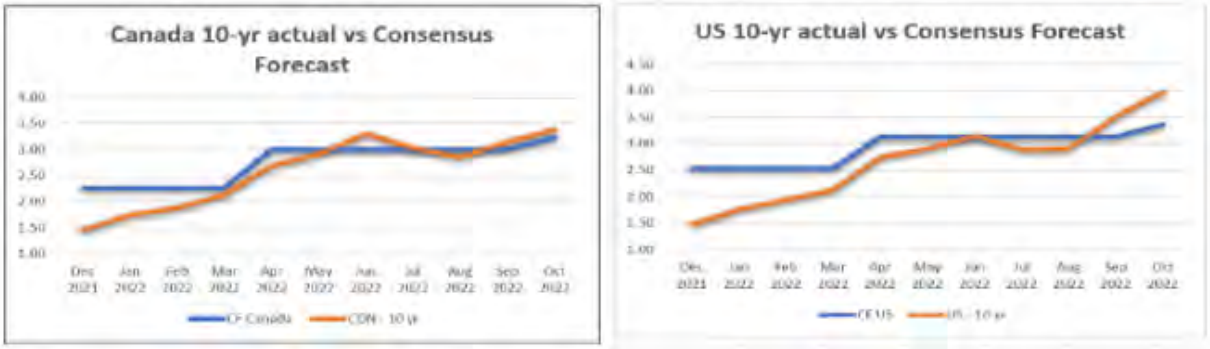
Regarding Dr. Lesser's view that based on the Efficient Market Hypothesis, "using a forecast of future yields on such bonds thus amounts to "double-counting" future expectations."[362] FortisBC remarks that Dr. Lesser concedes that "double- counting" is a misnomer, as Mr. Coyne is using the forecast instead of current bond yields (not adding them together). FortisBC also notes that Dr. Lesser acknowledges that investors look beyond the current price to inform investment decisions.[363]

In FortisBC's view, the reality is that current prices reflect many considerations other than investor expectations about the future, such as institutional investors settling trades at prices based on portfolio requirements:[364]

> A bond yield market is a chaotic place. There are billions and trillions of dollars traded each day in bond markets. Some traders have to get into positions, they have to get out of positions. They're optimizing what they need to do in that moment. That's different than having a three-to-five year outlook on what those markets are going to be.

FortisBC points out that forecast yields are now below the actual yields in both Canada and the US (see Figure 1). Thus, accepting Dr. Lesser's recommendation would, all else equal, increase Mr. Coyne's CAPM values. Dr. Lesser also agrees that Figure 1 shows that, regardless of whether one uses current or forecast bond yields, the cost of capital has increased since December 2021.[365]

Figure 1: Canada and U.S. 10-Yr Actual vs Consensus Forecast[366]



[361] FortisBC Final Argument, pp. 156–158.
[362] Exhibit A2-3, p. 46.
[363] FortisBC Final Argument, p. 158.
[364] FortisBC Final Argument, p. 158–159.
[365] Ibid., p. 161.
[366] Ibid., p. 162.

FortisBC submits that it is important to resolve this issue on a theoretical defensible basis, even if that means Mr. Coyne's CAPM results are lower than they otherwise would be if the BCUC were to adopt Dr. Lesser's recommendation.

Positions of Parties

ICG

Based on its support for the Efficient Market Hypothesis, ICG submits that model inputs should be based on current market prices rather than forecasts.[367]

BCOAPO

BCOAPO does not support or reject either expert's approach and notes that the results based on the October 2022 data are similar between the two experts, so provided that the BCUC uses the October 2022 data set to determine the ROE, there appears to be little difference in the risk-free rate regardless of which approach was used. However, this conclusion is entirely dependent upon the time period the BCUC chooses so BCOAPO submits that the approach chosen by the BCUC is important due to its potential influence on future panels.[368]

The CEC

The CEC notes that the experts disagree on the use of current government bond yields (Dr. Lesser) versus forecast government bond yields (Mr. Coyne) to determine the risk-free rate. The CEC submits that Dr. Lesser's concern with using data that may double-count investors' expectations has an important degree of validity. However, the CEC notes that the differences in the results are relatively small and that Mr. Coyne's choice appears to be the more conservative outcome. Therefore, the CEC supports Mr. Coyne's choice of forecast bond yields.[369]

RCIA

On the risk-free rate, RCIA notes that the debate is focused on whether to include a blend of actual and forecast rates (Mr. Coyne's method) or to use only actual rates (Dr. Lesser's). RCIA notes that any difference in risk-free rate estimates due to different assumptions will be 100 percent reflected in the calculated ROE based on the CAPM formula. Referencing the December 2021 and September 2022 data, RCIA concludes that the adoption of Mr. Coyne's assumptions regarding the risk-free rate results in a calculated ROE difference that does not track with actual changes in interest rates.[370] RCIA recommends adjusting Mr. Coyne's CAPM calculation by incorporating only actual risk-free rate data. [371]

FortisBC Reply Argument

[367] ICG Final Argument, pp. 6, 8.
[368] BCOAPO Final Argument, pp. 44–46.
[369] The CEC Final Argument, p. 41.
[370] RCIA Final Argument, pp. 11–14.
[371] Ibid., p. 20.

In reply to ICG's suggestion that using forecast bond yields is a rejection of the Efficient Market Hypothesis that underlies cost of capital models, FortisBC notes Mr. Coyne's observation that today's price not only incorporates future expectations but also additional investment considerations unrelated to what investors expect the price will be in the future. Were this not the case, there would be consistent alignment between current prices and forecasts. FortisBC states that this is one instance where clinging inflexibly to the academic Efficient Market Hypothesis is unhelpful to achieving a fair real-world result, considering that the Fair Return Standard is grounded in real-world considerations. FortisBC also points out that ICG's support for the rigid application of the Efficient Market Hypothesis in relation to risk-free rate is inconsistent with ICG's acceptance of using forecast bond yields in an AAM context.[372]

In response to RCIA, FortisBC notes that RCIA mischaracterized the nature of the disagreement between Mr. Coyne and Dr. Lesser on the risk-free rate when suggesting that Mr. Coyne proposed to use a blend of forecast and actual data. FortisBC points out that Mr. Coyne only used forecast bond yields. FortisBC also remarks that RCIA's focus on *ex post* forecast accuracy to oppose the use of forecasts because they are "fraught with uncertainty" misses the point. FortisBC states that the use of forecast bond yields recognizes that cost of capital is dictated by forward-looking investor expectation, and investors use forecasts.[373]

FortisBC also points out that RCIA uses the December 2021 data, despite the experts' agreement to use October 2022 data. Both forecast and actual bond yields increased significantly between these dates and FortisBC demonstrates that the differential between forecast and actual bond yield reverses in October 2022 such that the CAPM results based on actual bond yields rather than forecast bond yield would be 24 basis points (bps) higher, based on October 2022 data.[374]

Panel Determination

The risk-free rate is a key input in the CAPM, representing an estimate of the risk-free return that investors can expect to earn. Both experts agree that it is appropriate to base the estimated risk-free rate of return on the yield on long-term government bonds using a 30-year timeframe. None of the parties object to this approach. The Panel accepts this approach and notes that it is consistent with previous BCUC cost of capital decisions. We also recognize that the use of long-term rates is common in regulatory settings given that the rate of return is typically set for a longer period.

The experts disagree, however, on whether to estimate the risk-free rate using current or forecast bond yields. Consistent with views accepted in the 2016 FEI COC proceeding, Mr. Coyne states in his December 2021 evidence that since bond yields remain near historical lows, rates then do not reflect forward-looking circumstances because investors are factoring higher interest rates into their longer-term expectations and required returns. On the other hand, Dr. Lesser argues that the current yield already reflects investors' collective expectations about interest rates. ICG and RCIA support using current yields. The CEC and BCOAPO both note that the estimated risk-free rates using October 2022 data are similar between the two experts. Given we have already determined that using the October 2022 data is appropriate, we agree with BCOAPO that there appears to be little difference in the estimated risk-free rate regardless of which approach is used. This is especially the

[372] FortisBC Reply Argument, pp. 63–64.
[373] FortisBC Reply Argument, pp. 62–63.
[374] Ibid., p. 62.

case when using the 90-day average. Since recent increases in interest rates have impacted October 2022 results, we consider it reasonable to use the slightly longer 90-day period suggested by Dr. Lesser.

FortisBC points out that because the current yields are higher than the forecast yields in October 2022, Mr. Coyne's CAPM results are lower than they would be if the BCUC were to adopt Dr. Lesser's recommendation to use the current yield. Even though there is only a small difference between the current and forecast yields, FortisBC considers that the Panel should decide the "conceptually important issue" and argues that Mr. Coyne's forecast approach best reflects how investors make decisions because the current yield reflects additional investment considerations unrelated to what investors expect the price will be in the future. However, the Panel does not agree it is necessary to conclude on this issue for the purpose of setting the appropriate ROE for FEI and FBC in this proceeding because the October 2022 actual and forecast rates are closely aligned and interest rates are now trending above the historic lows in December 2021 that Mr. Coyne referred to.

We note that Mr. Coyne uses the forecast Canadian risk-free rate of 3.21 percent for the Canadian utilities in the North American proxy group and the forecast US risk-free rate of 3.50 percent for the US utilities in the North American proxy group. In Section 3.2, the Panel determined that it is appropriate to remove two Canadian utilities from the North American proxy groups and as a result, the risk-free rate would be weighted more towards the US risk-free rate than the Canadian risk-free rate. The Panel will consider the overall impact of this in Section 5.2.5 on Overall CAPM Results.

Based on the above determinations and subject to any adjustment noted in Section 5.2.5, **the Panel finds that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable.**

5.2.2 Beta

Beta is the systematic risk of an individual security and represents the risk of the security relative to the market. Mr. Coyne employs several methods of measuring the beta coefficient for the Canadian and US proxy groups using estimates from both Value Line and Bloomberg. Mr. Coyne explains that:

- Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index;
- Bloomberg produces beta estimates based on parameters entered by the user and Mr. Coyne computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/Toronto Stock Exchange (TSX) Composite as the market index; and
- Both Value Line and Bloomberg report adjusted betas.[375]

The following table presents the adjusted betas used by Mr. Coyne in his CAPM.

[375] Exhibit B-1-8-1, Appendix C, p. 57.

Table 12: Value Line and Bloomberg Betas[376]

October 2022	Value Line	Bloomberg
Canadian Group	0.80	0.88
U.S. Gas Group	0.84	0.80
North American Gas Group	0.84	0.88
U.S. Electric Group	0.89	0.89
North American Electric Group	0.88	0.86

Raw versus Adjusted Betas

Both experts recommend the use of Blume-adjusted betas to reflect a forward view of betas and their tendency to migrate toward the market mean over time, which is consistent with the forward-looking nature of estimating the allowed ROE for a utility.[377] Mr. Coyne also notes that both US utility regulators, including FERC, and the Brattle Group's 2012 study conducted for the BCUC also support the use of Blume-adjusted betas.[378]

One area of difference between the two experts is their data sources for adjusted betas. Mr. Coyne relies on Value Line and Bloomberg whereas Dr. Lesser recommends to only use Value Line to ensure consistency amongst all CAPM estimates,[379] as he notes that published betas can differ for the same firm due to differing estimating methods, historical periods, and data frequency being used.[380] However, Dr. Lesser also cautions that disputes over which published beta is "better," or whether practitioners should estimate their own betas, is likely to complicate the process for setting the allowed return.[381]

Despite Dr. Lesser's position, the evidence shows that Value Line does not publish adjusted betas for four out of six utilities included in Mr. Coyne's Canadian proxy groups.[382]

Adjusting Beta for Differences in Leverage

Dr. Lesser notes that, when applying the CAPM estimates of the proxy group to the utility under review, the differences in leverage must be accounted for.[383] If the capital structures of the proxy group firms differ significantly from the utility under review, as is the case for FEI and FBC, then the resulting CAPM estimates will not necessarily provide an accurate estimate of the required ROE.[384] For example, FEI's current deemed equity ratio is 38.5 percent while the average deemed equity ratio for the US gas proxy group is 53.4 percent.[385] To do this, the levered betas of the proxy group firms are unlevered to remove the financial risk component. The

[376] Information in the table has been compiled from Exhibit B1-50, Attachments A.2 FBC Electric, Tab "JMC-FBC-8.1 Avg CAPM" and FEI Gas, Tab "JMC-FEI-6.1 Avg CAPM".
[377] Exhibit B1-8-1, Appendix C, p. 59, Exhibit A2-20, BCUC IR 7.1, Exhibit A2-3, p. 42.
[378] Ibid., pp. 58–59.
[379] Exhibit B1-8-1, Appendix C, p. 59, Exhibit A2-20, BCUC IR 7.1.
[380] Exhibit A2-3, p. 41.
[381] Exhibit A2-20, BCUC IR 7.1.
[382] Exhibit B1-50, Excel Model A.2, Gas – Tab 6.1 and Electric – Tab 8.1.
[383] Exhibit A2-3, p. 43.
[384] Ibid.
[385] Exhibit B1-8-1, Appendix C, p. 120.

resulting beta values are called, asset betas. Next, these asset betas are re-levered using the capital structure of the regulated utility under rate review.[386] This can be done using the Hamada formula, shown below:[387, 388]

$$\beta_E = \beta_A \times \left[1 + (1 - t) \times \frac{D}{E}\right] \quad (2)$$

Where

β_E = the firm's pure equity beta
β_A = the firm's observed asset beta
D = the firm's amount of outstanding debt
E = the value of the firm's equity capital

In contrast, Mr. Coyne does not include an adjustment for leverage in his CAPM modelling because of his proposal to increase the equity ratio for FEI, reducing the disparity with those of the proxy groups and retaining FBC's existing equity ratio.[389] Mr. Coyne states that if the Hamada formula is used, as Dr. Lesser indicates is appropriate, the CAPM results for the US gas and US electric proxy groups are higher due to differences in the equity ratio between those proxy groups and the utilities under review.[390]

FortisBC notes that Mr. Coyne confirms his "complete alignment" with Dr. Lesser regarding the need to account for disparities in financial risk and the methods to do so (i.e. the Hamada adjustment to adjust the ROE in the CAPM analysis). Since FEI and FBC currently have significantly lower common equity ratios relative to the proxy group companies, the Hamada adjustment would increase the ROE relative to the one suggested by Mr. Coyne's model outputs. However, Mr. Coyne did not adjust the ROE results upwards to account for FEI and FBC's thinner equity. Instead, he has chosen to address the discrepancy in financial risk through his recommended capital structure because he notes that this is most consistent with how the BCUC typically accounts for differences in relative risk.[391]

Consequently, FortisBC highlights this issue as an important take-away for the BCUC. FortisBC submits that the BCUC cannot approve a common equity ratio below 45 percent for FEI and 40 percent for FBC without also adjusting the CAPM results upwards. This upward adjustment in ROE would be necessary to offset the larger disparity in financial risk.[392]

Positions of Parties

BCOAPO

On the topic of beta values, BCOAPO notes the agreement of both experts to use adjusted betas as opposed to raw betas and their reliance on different data sources for their betas. BCOAPO states that beta estimates are not

[386] Exhibit A2-3, p. 43.
[387] Ibid., pp. 43-44.
[388] The steps are: 1) the levered betas of the proxy group firms are unlevered to remove the financial risk component; and 2) the resulting betas (asset betas) are re-levered using the capital structure of the regulated utility under review. (Exhibit A2-35, p. 43).
[389] Transcript Volume 3, pp. 271–274.
[390] Exhibit B1-8-1, Appendix C, p. 59.
[391] FortisBC Final Argument, pp. 174–175.
[392] Ibid., pp. 176–177.

available from Value Line for all the gas and electric utilities included in Mr. Coyne's proxy groups and notes that, where values were available from both Value Line and Bloomberg, neither source consistently provides higher or lower values. Therefore, BCOAPO submits that Mr. Coyne's approach to use the average of values published by Value Line and Bloomberg is more appropriate.[393]

Furthermore, BCOAPO notes that both experts agree that it is possible to consider differences in financial leverage between the proxy groups' companies and FEI and FBC by adjusting the authorized ROE. While not specifically addressing the CAPM, BCOAPO also submits that, in conjunction with its recommended increase in deemed equity from 38.5 percent to between 40 to 42 percent, it would be reasonable to help recognize the differences in financial leverage between FEI and the North American gas proxy group by increasing FEI's ROE to 9.50 percent from the 9.38 percent calculated using the models.[394]

In order to help recognize both the financial leverage difference between FBC and the North American electric proxy group and the implications that size difference has on the CAPM results, BCOAPO submits that it would be reasonable for the BCUC to set FBC's authorized ROE at 9.5 percent as opposed to 9.01 percent as calculated using the models.[395]

The CEC

The CEC finds that, on balance, the evidence before the BCUC does not support additional adders to the FEI and FBC ROEs for differences in financial leverage and does not support, at this time, moving the equity thicknesses to those of the US proxy groups.[396] The CEC recommends that the BCUC remain sensitive to the trade-offs between equity thickness and the allowed ROEs, and consider in its AAM processes the possibility for both to be reviewed and adjusted on a formulaic basis.[397]

RCIA

Regarding the beta values, since there do not appear to be significant differences in the assumptions of the two experts, RCIA is not opposed to the beta values used by Mr. Coyne.[398]

FortisBC Reply Argument

In reply, FortisBC notes that BCOAPO acknowledges that there is a need to adjust the ROE upwards for FEI's relative financial risk compared to proxy groups, and states that BCOAPO's ROE recommendations include such an adjustment. BCOAPO does not state explicitly how much of an upward adjustment it has included for FEI's ROE but FEI states that this amount can be readily back-calculated as being only 12 bps. FortisBC submits that this is clearly insufficient, as a Hamada adjustment would increase the ROE by almost four times that amount.[399]

[393] BCOAPO Final Argument, p. 51.
[394] Ibid., p. 58.
[395] Ibid.
[396] The CEC Final Argument, p. 54.
[397] Ibid., p. 55.
[398] RCIA Final Argument, p. 11.
[399] FortisBC Reply Argument, p. 46.

Panel Determination

Beta is a key input into the CAPM and relies on a proxy group of companies to estimate the risk of FEI and FBC compared to the whole market. Consistent with common practice, Mr. Coyne uses five years of data in his analysis. His estimates are based on data from two credible third-party sources (Value Line and Bloomberg). In contrast, Dr. Lesser prefers to only use Value Line data to ensure consistency amongst all CAPM estimates. However, the evidence shows that Value Line does not publish adjusted betas for several of the utilities included in Mr. Coyne's Canadian proxy groups. Given this, the Panel agrees with BCOAPO that since there appears to be no upward or downward bias in either source of data, Mr. Coyne's approach using the average of values published by Value Line and Bloomberg is reasonable.

In Section 3.2, the Panel determines it appropriate to remove two Canadian utilities from the Mr. Coyne's North American proxy groups in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which, since as stated by Mr. Coyne during the oral hearing, these companies were unlikely to have passed his screening criteria if applied strictly. This change impacts the overall beta result. The Panel will consider the overall impact of this in Section 5.2.5 on Overall CAPM Results.

Both experts agree that it is appropriate to use Blume-adjusted betas to reflect a forward-looking view and to adjust the raw data for the observed tendency of betas to migrate toward the market mean over time. Consistent with the views of the experts, the use of adjusted betas is accepted by US utility regulators, including FERC.

Mr. Coyne states that he is not aware of any Canadian jurisdiction that has specifically endorsed the use of Blume adjusted betas.[50] The BCUC has not accepted Blume-adjusted betas in previous proceedings. In the 2016 Decision, the BCUC placed limited weight on the experts' adjustments to beta because of a lack of empirical evidence supporting the applicability of the Blume adjustment to utility stocks.[51] Likewise, in the 2013 Decision, the BCUC stated:

> An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.[52]

However, the Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule.[53] Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.

The Panel agrees with the experts that there is a need to account for leverage differences in the proxy group of companies and acknowledges that the Hamada adjustment is an appropriate approach to adjust for FEI and FBC's thinner equity. However, given that Mr. Coyne did not provide an October 31, 2022 update identifying the impact of the Hamada adjustment on his CAPM results, we accept Mr. Coyne's approach to addressing the discrepancy in financial risk through an adjustment to the capital structure. We agree this approach is consistent with how the BCUC typically accounts for relative risk. In determining an appropriate capital structure for FEI

and FBC as set out in Section 6.3, we acknowledge FortisBC's submission that Mr. Coyne's CAPM results are based on a common equity ratio of 45 percent for FEI and 40 percent for FBC.

5.2.3 Market Risk Premium

The MRP is the difference between the expected total return on a broad market portfolio and the return on the risk-free investment. Mr. Coyne describes the MRP as the amount that investors expect to earn above the risk-free rate as compensation for owning common stock, which is considered higher risk than government bonds.

To estimate the MRP, Mr. Coyne explains that:

- Estimates of the MRP generally fall into two categories, ex-post (historical arithmetic average) and ex-ante (forward-looking);
- The historical MRP is based on the arithmetic mean of the average annual return on large company stocks less the income-only return on long-term government bonds based on historical data from Duff & Phelps, a well-respected source of financial information for investors;
- The forward-looking MRP is calculated by subtracting the risk-free rate from the estimated total return for the overall market, using a DCF model applied to a proxy group for the market as a whole, such as the S&P 500 or the TSX; and
- First, an overall expected market return is estimated. Then, the risk-free rate is subtracted to get the MRP.[400]

Both experts acknowledge that the MRP can be calculated on either an historical or forecast basis.[401] Dr. Lesser notes that it is acceptable to average an historical MRP with a forward-looking MRP, using Mr. Coyne's methodology, if the forward-looking MRP is estimated using a reasonable methodology. However, Dr. Lesser does not consider the single-stage DCF approach (also known as the constant DCF approach) used by Mr. Coyne to be a reasonable approach to estimate a forward-looking MRP.[402]

Constant versus Multi-Stage DCF Model to Estimate the MRP

As noted above, a key area of difference between the two experts is whether to estimate the forward-looking MRP using the Constant DCF model, as advocated by Mr. Coyne, or the Multi-Stage DCF model, as preferred by Dr. Lesser.[403]

Mr. Coyne notes that a constant-DCF approach is consistent with the method used by FERC.[404] This method applies a single-stage DCF to the dividend-paying firms of the S&P 500 to estimate the market return and MRP, which Mr. Coyne considers appropriate because: (i) the S&P is updated regularly to remove slow-growing firms and (ii) that even though an individual company cannot sustain high growth rates forever, a broad market index can do so. The Constant DCF model employed by Mr. Coyne uses analyst growth forecasts for the S&P 500 and

[400] Exhibit B1-8-1, Appendix C, pp. 59–60.
[401] Exhibit B1-8-1, Appendix C, p. 60, Exhibit A2-5, BCOAPO IR 8.1.
[402] Exhibit A2-24, BCOAPO IR 18.4.4.
[403] Exhibit B-21, p. 5.
[404] Exhibit B1-8-1, Appendix C, p. 61.

TSX because those estimates reflect expectations of what an investor could earn by investing long-term in those indices. The analyst growth forecasts generally refer to a period of between three to five years.[405]

Dr. Lesser cautions regulators adopting the forward-looking approach to be aware that using a Constant DCF model is likely to yield estimates of market returns that are unreasonably high and statistically improbable.[406] In Dr. Lesser's opinion, FERC's rationale is based on a misconception. He explains:

> Using the expected returns for the S&P 500 or the TSX represent a proxy for the entire market. […] In the long-run, the market cannot grow faster than the economy as a whole for the simple reason that the market, in effect, is the economy.[407]

In response, Mr. Coyne points to his evidence that the historical growth rates of regulated utilities in Canada and the US as measured by earnings per share and dividends per share growth, have been higher than nominal growth domestic product (GDP) over 2005 to 2019, which also supports a view that the broad market can increase by more than the level of GDP growth (since utilities are generally slower growth companies). Mr. Coyne also states that since the S&P 500 consists of the most successful companies, they should not be expected to represent the economy overall, as implied by GDP.[408] However, Dr. Lesser disagrees with Mr. Coyne on this as he explains that, under the CAPM, the expected return in the market refers to the return on all publicly traded securities, not just a single proxy group such as the S&P 500:

> Mr. Coyne's "evidence" that the growth in the S&P 500 has exceeded GDP growth is therefore irrelevant. The entire market cannot grow faster than the economy in the long-run because the entire market effectively is the economy.[409]

Average of historical and forward-looking MRP versus forward-looking only MRP

Mr. Coyne uses an average of the historical MRP[410] and the forward-looking MRP across both Canada and the US Dr. Lesser relies on a country-specific, forward-looking MRP only.[411] Dr. Lesser recommends the use of a Canadian MRP for the Canadian proxy group, a US MRP for the US proxy groups, and an average of the two countries' MRP for the North American proxy groups.[412]

Mr. Coyne justifies his "averaging" method on the fact that the two economies are highly integrated and capital flows freely between them. Thus, the risk premiums for each country are highly correlated such that it is reasonable to derive a single forward-looking MRP estimate for both countries by averaging the four estimates.[413]

[405] Exhibit B1-9, BCUC IR 39.8.2.
[406] Exhibit A2-3, p. 52.
[407] Ibid.
[408] Exhibit B1-9, BCUC IR 39.4.
[409] Exhibit A2-24, BCOAPO IR 18.5.
[410] The historical MRP for the US is calculated over the period from 1926 to 2020, while in Canada, the historical MRP covers the period from 1919 to 2020. Exhibit B1-9, BCUC IR 40.1.
[411] Exhibit B1-21, pp. 17–18, Exhibit B1-8-1, Appendix C, p. 60.
[412] Transcript Volume 3, p. 211, Lines 1–6.
[413] Exhibit B1-8-1, Appendix C, p. 60.

In addition, Mr. Coyne explains that given the low-rate environment in December 2021, he would tend to place more reliance on the forward-looking MRP in the CAPM analysis. Mr. Coyne points to FERC's exclusive reliance on a forward-looking MRP in the CAPM and to Dr. Lesser's support for the use of a forward-looking MRP.[414] Despite this view, Mr. Coyne still proposes to take a simple average of these four estimates to estimate the MRP, citing the fact that there is a lot of controversy in Canada around what is the forward-looking MRP. By averaging both the historical and forward-looking MRPs, Mr. Coyne, brings both perspectives into play, stating, "being sympathetic to those who would argue that 100 years of history means something". Mr. Coyne continues and states, "if left to my own druthers absent that debate I'd probably give [the forward approach] 100 percent weight."[415]

The following table presents Mr. Coyne's historical and forward-looking MRPs for Canada and the US based on October 2022 data, where Mr. Coyne uses the Constant DCF model to derive the forward-looking MRPs.

Table 13: Market Risk Premiums – Canada and U.S. – October 2022[416]

	Canadian MRP	U.S. MRP
Historical	5.74%	7.46%
Forward-Looking	7.74%	8.21%
Average	7.29%	

In comparison, the forward-looking-only MRPs derived by Mr. Coyne using his interpretation of Dr. Lesser's preferred approach, i.e. the Multi-Stage DCF model, are shown in the table below. This approach to calculating the MRPs yields significantly lower MRPs than Mr. Coyne's and has a commensurate impact on the overall CAPM estimates.

Table 14: Market Risk Premiums – Canada and U.S. – October 2022[417]

Forward-looking MRP	Canada	U.S.
	October 2022	
30-day	5.47%	3.30%
90-day	5.66%	3.78%

FortisBC submits that the experts agree that the forward-looking MRP should be computed based on the total return on the S&P 500 Index (for US proxy groups) and the TSX (for Canadian proxy groups) but disagree on how to compute it. Fortis BC states that Mr. Coyne uses the Constant DCF model, like FERC, moderated by giving 50 percent weighting to historical data. FortisBC argues that Mr. Coyne's "very conservative approach" of averaging the constant growth DCF forward-looking MRP with historical returns is a concession to past controversy about how to forecast the forward-looking MRP.[418] FortisBC argues that although Dr. Lesser previously shared Mr.

[414] Exhibit B1-8-1, Appendix C, pp. 60–62.
[415] Transcript Volume 3, p. 217, Lines 21–15 to p. 218, Lines 1–14.
[416] Exhibit B1-50, Attachment A.2 FBC – Electric (Oct 2022 update 90 day), Tab JMC-FBC-8.1 Avg CAPM, Cell G6 or Attachment A.2 FEI – Gas (Oct 2022 update 90 day), Tab JMC-FEI-6.1 Avg CAPM, Cell G6.
[417] Information in the table has been compiled from Exhibit B1-50, Table 1, p. 2.
[418] FortisBC Final Argument, pp. 163–164.

Coyne's approach, he now advocates for a Multi-Stage DCF model, which is the reason for the very low Lesser CAPM result.[419]

FortisBC argues that applying Dr. Lesser's methodology and assuming that companies in the S&P 500 are only going to grow at the rate of GDP growth starting in Year 6 is not realistic. FortisBC notes that Dr. Lesser states that "companies absolutely can grow faster than GDP after five years".[420] FortisBC submits that Mr. Coyne provided evidence to back that up, showing that over a 92-year period (1929 to 2020), average annual returns on large company stocks have exceeded nominal GDP growth by 5.55 percent and that earnings per share (EPS) and dividend per share (DPS) of regulated utilities in Canada and the US grew faster than nominal GDP over the period 2005 to 2019. Since utility companies are generally slower growth companies, Mr. Coyne observes that it stands to reason that the broad market can also increase by more than the level of GDP growth.[421]

FortisBC submits that the forward-looking only MRPs derived from using Dr. Lesser's preferred approach produces an MRP that "defies logic":[422]

> A U.S. MRP of 3.30% or 3.78% […] is outside any reasonable range of the MRP estimates and 3.5% to 4.0% lower than the historical U.S. MRP of 7.46% from 1929-2021. […]
>
> Using Dr. Lesser's method for calculating the forward-looking MRP produces CAPM results that are well below the multi-stage DCF model results, the constant growth DCF results and the risk premium model results. This calls into question the reliability of the CAPM results using Dr. Lesser's inputs.

Positions of Parties

ICG

ICG notes that Mr. Coyne used the same approach for estimating the MRP in a testimony before the Alberta Utilities Commission (AUC) and that the AUC rejected Mr. Coyne's approach to calculating the MRP for the CAPM by giving it no weight because of unsupported and very high ROE recommendations. ICG submits that the BCUC should do the same. And although FERC also uses a Constant Growth DCF MRP, Dr. Lesser provides a comprehensive explanation as to why he does not support that approach.[423]

BCOAPO

BCOAPO submits that Mr. Coyne's argument in favour of using the Constant DCF model to estimate the forward-looking MRP is flawed. BCOAPO explains that an MRP is supposed to be based on the expected returns of the overall market, but indices like the S&P 500 do not represent the overall market and even the S&P 500 is biased, as it only includes companies with high capitalization.[424] Thus, BCOAPO submits that the Panel should consider results from the CAPM where the MRP is based on a Multi-Stage DCF model as recommended by Dr. Lesser.

[419] FortisBC Final Argument, pp. 162–163, 167.
[420] Ibid., p. 165.
[421] Ibid., p. 165–166.
[422] FortisBC Final Argument, p. 166–167.
[423] ICG Final Argument, pp. 3, 11, 13, 15.
[424] BCOAPO Final Argument, p. 50.

Furthermore, BCOAPO submits that a more appropriate way to compare Mr. Coyne and Dr. Lesser's CAPM results would be to apply Mr. Coyne's averaging of historic and forecast MRP values to Dr. Lesser's CAPM methodology. In this way, BCOAPO submits that the Panel can compare apples to apples.[425] BCOAPO recalculates the "Lesser CAPM results" by replacing the MRP values with the average of the historic and forward-looking values. The BCOAPO-revised results are shown as "Lesser – Average CAPM (BCOAPO)" in the following table:

Table 15: BCOAPO Summary of CAPM ROE (excluding flotation costs) – October 2022 (90- Days)[426]

Proxy Groups:	Canada	U.S. Electric	NA Electric	U.S. Gas	NA Gas
Coyne – Average CAPM	9.62%	9.46%	9.80%	10.01%	9.74%
Lesser – Average CAPM (BCOAPO)	8.09%	8.45%	8.23%	8.03%	8.27%

BCOAPO concludes that "[j]ust as averaging tends to bring Mr. Coyne's results closer to those produced by the Multi-Stage DCF model, averaging also does the same for Dr. Lesser's. As a result, just as Mr. Coyne has characterized his use of averaging as "more conservative than relying solely on the forward-looking MRP", the same could be said for the use of averaging in Dr. Lesser's approach."[427]

The CEC

The CEC submits that Mr. Coyne's 50 percent split (between historical and forward-looking) helps moderate the result, and the CEC would support a weighting for additional historical data and lower weighting for the forward-looking data, which could justify a 70 to 90 bps reduction for the modelling data.[428]

The CEC also recommends that the BCUC adjust its overall ROEs for FEI and FBC downward by 80 bps for the CEC's perception that the modelling results are too forward looking and should be more grounded in the current and historical data.[429]

Regarding the use of the DCF model to estimate the MRP, the CEC notes that Dr. Lesser proposes the Multi-Stage DCF model whereas Mr. Coyne uses the Constant DCF model. The CEC states that Dr. Lesser's approach to limiting forecast market returns to five years and in Year 6 using forecast GDP was debated, with Mr. Coyne providing evidence showing that average returns on large company stocks, and even on regulated Canadian and US utilities, exceeded GDP growth historically. Based on these observations, the CEC submits that the arguments of Mr. Coyne appear to have merit for his CAPM modelling and that Dr. Lesser's CAPM modelling should not be used. The CEC does not support the view that the market is the economy and that it therefore cannot grow more than the GDP of a country in which that market operates (i.e. Dr. Lesser's view).[430]

[425] BCOAPO Final Argument, p. 49.
[426] BCOAPO Final Argument, p. 49.
[427] Ibid., p. 50.
[428] The CEC Final Argument, p. 41.
[429] Ibid., p. 43.
[430] Ibid., pp. 41–42.

RCIA

RCIA notes that the Canadian MRP, both historic and forward looking, is markedly lower than the US MRP. While Mr. Coyne justifies averaging the four MRP estimates to use in his CAPM formula based on the highly integrated nature of the Canadian and US markets, RCIA submits that there is no evidence to suggest that this integration is not already reflected within the respective market calculated MRP values.

RCIA also submits that the Canadian MRP should only be measured against the Canadian proxy group as being country (and market) specific. RCIA shows that the average of the historic Canadian MRP (5.54 percent) and the historic U.S MRP (7.25 percent) results in an MRP of 6.40 percent. Thus, Mr. Coyne's CAPM results are biased upwards by 77 bps relative to a Canadian-only MRP.[431] Although RCIA does not support the inclusion of US data in the calculation of ROE for FEI and FBC, if the BCUC were to accept it, RCIA submits that there is no evidence to support an equal weighing of Canadian and US data.[432]

In addition, RCIA comments on Mr. Coyne's approach to averaging both historic and forward-looking MRPs. RCIA notes that, while the historical US MRP was 7.25 percent over the 1926 to 2022 period, Mr. Coyne calculates and assumes that the difference between the stock market performance and the US bond yield will average 12.08 percent on a forward-looking basis. RCIA then cites Dr. Lesser's evidence that "forward market risk premiums that might be 12 or 13 percent" are in his view "a statistical impossibility".[433] Further, RCIA notes that Mr. Coyne's average MRP of 8.49 percent above the risk-free rate seems highly questionable when looking at historical Canadian MRPs.[434] RCIA concludes that in the context of a Canadian utility, Mr. Coyne's forward-looking MRP assumptions are not an impossibility, but history suggests them to be quite improbable.[435]

RCIA recalculates the average MRP based only on Canadian historic and forward-looking MRP and obtains 7.32 percent. RCIA points out that this level would have been exceeded only twice in the last ten decades. Thus, RCIA submits that Mr. Coyne's assumption of equal weighting of historical and forward-looking MRP biases the resulting MRP upward. RCIA submits that a much lower weighting of the forward-looking MRP may be appropriate such as 75 percent historical and 25 percent forward-looking. A 75-25 blending of Canadian historical and Canadian forward-looking MRPs results in an MRP assumption of 6.43 percent.[436] RCIA states this estimate would have been exceeded three times over the past ten decades. Thus, RCIA recommends using a 75-25 weighting as opposed to the 50-50 weighting of only Canadian data as it provides a better directional alignment with the available data. Based on Concentric's beta of 0.89, the CAPM result under this weighting would be approximately 79 bps lower than one derived from an equal weighting of historical and forward-looking data.[437,438]

[431] The difference (6.40 % - 5.54 %) multiplied by a beta of 0.89 equals 77 bps.
[432] RCIA Final Argument, pp. 15–17.
[433] Ibid., pp. 17–18.
[434] Ibid., p. 18.
[435] Ibid., pp. 18–19.
[436] 0.75 x 5.54% + 0.25 x 9.10% = 6.43%.
[437] (7.32%-6.43%) x 0.89 (Beta).
[438] RCIA Final Argument, p. 19.

FortisBC Reply Argument

In reply, FortisBC submits that ICG has misinterpreted the AUC's approach in the AUC 2018 Decision cited by ICG. In that decision, the AUC rejected all forward-looking DCF estimates, both single and multi-stage, in favour of relying exclusively on historical MRP data. Thus, using the AUC approach in the context of this GCOC proceeding would produce a higher MRP than Dr. Lesser's since historical MRPs are higher than MRPs calculated using a two-stage approach. FortisBC adds that there is no evidence on record showing that investors' expected return is equal to historical returns and as such, there is no support to rely only on historical MRPs like the AUC did in 2018.[439]

FortisBC also rejects BCOAPO's critique of using the Constant Growth DCF model to estimate the MRP as being flawed. FortisBC notes both experts' agreement that broad market indices (e.g. S&P 500) can be used as proxy for the entire market and that the evidence shows that these indices can and do grow more than GDP over long periods.[440]

FortisBC also submits that, while BCOAPO acknowledges an increase in the cost of capital since the last GCOC proceeding, its calculations still understate the required ROE due to their reliance on the Lesser CAPM result and mathematical errors.[441] FortisBC reiterates that the Lesser CAPM results are implausibly low due to a very low MRP and that even Dr. Lesser questions the validity of such low ROE results. Including unreasonably low results in an average, as BCOAPO has done, also makes the resulting average unreasonably low.

FortisBC states that BCOAPO implicitly acknowledges that the two-stage CAPM results are unreasonable because they adjust the forward-looking MRP upwards by averaging the forecast MRP with the historical average MRP. As BCOAPO notes, Mr. Coyne's CAPM results were already conservative due to his decision to base the MRP on a 50:50 blend of forecast and historical data. FortisBC concludes, there is no need to average Mr. Coyne's conservative CAPM results with any other CAPM results, adjusted or not. FortisBC states that, while BCOAPO's adjustment reduces the considerable gap between the Lesser CAPM results and every other model and reasonableness check, the adjusted results are still an outlier. Thus, the BCUC should only be using Mr. Coyne's CAPM analysis.[442]

In reply to the CEC, FortisBC explains why the CEC's recommended 80-bps downward adjustment is problematic: a) the CEC conceded that Mr. Coyne is already "conservative" in giving 50 percent weighting to historical MRP data; b) the CEC offers no explanation for how it arrived at this 80-bps adjustment; and c) this deduction is inconsistent with financial theory as CAPM analysis is intended to be forward looking. FortisBC states that it is a big and unjustified leap from the CEC's contention that "investors are not exclusively forward-forecast focused" to placing most of the weight on historical data.[443]

[439] FortisBC Reply Argument, pp. 69–70.
[440] FortisBC Reply Argument, p. 70.
[441] Ibid., p. 44.
[442] Ibid., pp. 45, 70.
[443] Ibid., pp. 42-43

In response to RCIA's use of Canadian data only for MRP, FortisBC submits that RCIA's view is flawed because:

- An inference cannot be drawn about relative expected returns of utilities in Canada versus the US from a differential in the countries' MRP;
- The MRP is a measure of potential earnings from investing in the market as a whole, not of relative expected returns; and
- The MRP differential between Canada and the US is due to the indices' different industry weightings, not expectations about utility earnings.

FortisBC also notes Dr. Lesser's support for averaging the Canadian and US MRP when looking at North American proxy groups. FortisBC remarks that this averaging approach is potentially conservative, as it would also be reasonable to only use US MRP since a potential investor in FEI/FBC can, as an alternative, obtain the US market return by investing in the S&P 500. FortisBC recalculates RCIA's downward adjustment based on October 2022 data to be 49 bps instead of the 77 bps calculated by RCIA based on December 2021 data.[444]

Furthermore, FortisBC rejects RCIA's assertion that Mr. Coyne's 50:50 approach biases the resulting MRP upwards. Instead, FortisBC considers that giving 50 percent weight to the historical MRP introduces a downward bias of approximately 180 to 190 bps. RCIA's use of a 75:25 blend further suppresses Mr. Coyne's already conservative 50:50 weighting. This is contrary to the consensus expert evidence that the MRP is intended to be forward looking, and Mr. Coyne is clear that his approach is only a pragmatic response to the controversy surrounding MRPs.

Panel Determination

The MRP is a key input into the CAPM. It represents the premium above the risk-free rate that equity investors demand to compensate them for the extra risk they accept when they invest in riskier assets. As Dr. Lesser notes, the theory underlying the CAPM includes all assets in the market (art, real estate, bonds, stocks, etc.). However, the two experts agree that, while there is no perfect proxy for the market, broad market indices such as the S&P 500 and TSX can be used as proxy for the entire market. Given the integration of North American markets, we accept their view, noting that several of the proxy group companies are included in these indices.

Since investor expectations are future focussed, we also support the experts' view that it is appropriate to consider forward-looking estimates in determining the MRP. We also accept that using a DCF approach based on the Bloomberg analysts' long-term growth rate estimates of companies included in the broad market indices is acceptable and is a reasonable starting point for estimating expected market returns. We note that Bloomberg explains that its long-term growth forecasts are received directly from contributing analysts and while different analysts apply different methodologies, the long-term growth forecast generally represents an expected annual increase in operating EPS over the company's next full business cycle. In general, these forecasts refer to a period of between three to five years.[445]

A key determinant for the Panel regarding the forward-looking MRPs is assessing the reasonableness of the growth expectation for the period beyond the five years estimated by analysts. The two experts differ on how to

[444] FortisBC Reply Argument, pp. 64–67.
[445] Exhibit B1-9, BCUC IR 39.8.2.

approach this issue. The Constant DCF model used by Mr. Coyne assumes the three-to-five-year analyst growth forecasts continue in perpetuity. Dr. Lesser prefers a multi-stage DCF approach that reverts to a GDP growth rate at a later stage. He cautions that relying on a constant growth DCF model is likely to yield estimates of market returns that are unreasonably high and statistically improbable.

The Panel places little weight on the two-stage forward-looking MRP model derived by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach. In this model, Mr. Coyne reverts to a GDP growth rate after five years. We agree that the MRP estimates produced using this assumption are too low and note that Dr. Lesser also questions the results. However, we object to FortisBC's characterization of this output as "the Lesser CAPM result". Dr. Lesser did not prepare this evidence and we do not know what result Dr. Lesser would have presented if he had been engaged to prepare ROE recommendations for FEI and FBC. Given that we place no reliance on the two-stage MRP estimate prepared by Mr. Coyne based on his interpretation of Dr. Lesser's approach, we agree with FortisBC that we should not be adjusting these results in the manner suggested by BCOAPO.

The Panel acknowledges that the evidence shows that market indices can and have grown by more than GDP over long periods. However, we have no evidence to support that investors expect the MRP to grow at the rates reflective of analyst forecasts in perpetuity. Given the recent market volatility and the downturn in market results over the last few years, it is not unreasonable that investors are expecting a higher return over the next five years. However, the Panel is not convinced that what follows is that investors expect an MRP of 8.0 percent[446] in the future compared to the long-term historical average Canadian and US MRP of 6.6 percent.[447]

Accordingly, the Panel must consider the extent to which it should rely on historic MRPs. While Dr. Lesser prefers a forward-looking MRP estimate, he explains that the economic rationale for using an MRP value based on historical data is that the future will resemble the past and the going-forward MRP will be similar to its average value in the past.[448] Mr. Coyne also prefers a forward approach but uses a 50:50 weighting of historic and forward data, "being sympathetic to those who would argue that 100 years of history means something." The Panel notes Mr. Coyne's concern in December 2021 that the historical MRPs would have underestimated the MRP in the then low interest rate environment due to the inverse relationship between interest rates and the MRP.[449] However, the Panel's reliance on October 2022 data, with higher interest rates, should alleviate this concern with using historical data.

FortisBC argues, because there is no evidence on record showing that investors' expected return is equal to historical returns, there is no support to rely only on historical MRPs like the AUC did in 2018 as suggested by ICG or to place greater weight on historical data as argued by RCIA and the CEC. As noted above, we also support the experts' view that it is appropriate to consider forward-looking estimates in determining the MRP. However, we disagree with FortisBC that there is no evidence to support the use of historic returns. As both experts noted, historic returns are regularly accepted as a basis on which to predict future returns. We also disagree with FortisBC that Mr. Coyne's 50 percent weight on historic MRPs is conservative.

[446] (7.74+8.21)/2.
[447] (5.74+7.46)/2.
[448] Exhibit A2-3, p. 47.
[449] Exhibit B1-8-1, Appendix C, p. 60.

In our view, the 50:50 weighting of historic and forward MRPs sufficiently balances and moderates the unsupported assumption that higher analyst expectations over the next five years are expected to continue in the future with the actual achieved MRPs over a long history. As a result, the Panel rejects ICG's submission to only use historical returns and RCIA and the CEC's submission to place greater weight on historical data, along with the related downward adjustment to the CAPM results that they both recommend.

We also reject RCIA's submission that we should use Canadian data only. Investors are free to invest in either the Canadian or US market. In our view, a simple averaging of the two is supportable for this reason and simplifies the estimation process.

5.2.4 Size Premium

Another issue with the CAPM is the size effect, which stems from an observation that smaller firms (where size is measured by market capitalization) tend to have higher returns than predicted by the CAPM.[450] Mr. Coyne notes that the BCUC previously found that the authorized ROE for FBC should be 40 bps higher than that of FEI due, in part, to the small size of FBC.[451] Dr. Lesser explains that to measure size premiums, most analysts rely on the Center for Research in Security Prices (CRSP)'s size premium estimates for 10 groups of market capitalization, published each year by Duff & Phelps.[452] Dr. Lesser typically incorporates a size premium in his analysis.[453]

While Mr. Coyne did not add a size premium to his CAPM ROE results, he nonetheless uses the Duff & Phelps data to calculate the size premium required for FBC. Mr. Coyne explains that his approach is to calculate the difference between the size premium associated with the average or median market capitalization of the US electric proxy group companies and the size premium associated with FBC's market capitalization.[454] Since the median market capitalization of the companies in his US electric proxy group falls in the second decile and that of FBC falls in the seventh decile, using the Duff & Phelps table, Mr. Coyne calculates that FBC's small size relative to his US electric proxy group companies would justify a size premium of approximately 105 bps (i.e. 1.54% - 0.49%).[455]

Dr. Lesser commented that Mr. Coyne's approach is without theoretical basis and arbitrary.[456] Rather, Dr. Lesser would adjust the CAPM estimates of each proxy group company by the required size premium so that the CAPM results would include a size adjustment.[457] This is also the methodology used by FERC to calculate the size premium.[458] Mr. Coyne calculates the size premium according to Dr. Lesser or FERC's methodology as 30 bps for the US electric proxy group and 38 bps for the North American electric proxy group.[459]

[450] Exhibit A2-3, p. 55.
[451] Exhibit B1-21, Part 2, p. 28.
[452] Exhibit A2-3, p. 55.
[453] FortisBC Final Argument, p. 177.
[454] Transcript Volume 4, p. 470, Lines 5–8.
[455] Exhibit B1-8-1, Appendix C, p. 5, Transcript Volume 4, p. 464, Lines 7–10.
[456] Transcript Volume 4, p. 471, Lines 7–10.
[457] Ibid., p. 468, Lines 4–23.
[458] Exhibit B1-50, p. 1.
[459] Ibid., Figures 14 and 16, pp. 11–12.

FortisBC submits that the experts agree that the CAPM underestimates the cost of equity for smaller companies and that the BCUC should find that Mr. Coyne's CAPM results for FBC are understated[460] and should consider a size premium for FBC, which is much smaller than the electric proxy group companies.[461] FortisBC notes that the BCUC has previously found, exercising a judgment-based approach, that the authorized ROE for FBC should be 40 bps higher than that of FEI due, in part, to the small size of FBC. This is smaller than what the Duff & Phelps table would indicate.[462] In short, FortisBC submits that the BCUC should find that Mr. Coyne's CAPM results for FBC are very conservative by virtue of not including a size premium of 105 bps, or alternatively, a minimum of 40 bps.[463]

Positions of Parties

BCOAPO

BCOAPO cites Mr. Coyne and Dr. Lesser who both acknowledge a "size effect" and notes that, while Mr. Coyne has not included a size adjustment in his ROE recommendations for FBC, he nonetheless calculates a size premium of 105 bps would be justified relative to the US electric proxy group companies.[464]BCOAPO surmises that similar results would likely apply to the revised North American electric proxy group which is made up largely of utilities from the US electric proxy group.[465]

BCOAPO submits that it would be reasonable for the BCUC to recognize the implications of this size difference on FBC's CAPM results. BCOAPO submits that in order to help recognize both the financial leverage difference between FBC and the North American electric proxy group and the implications that size difference has on the CAPM results, it would be reasonable for the BCUC to set the authorized ROE for FBC at 9.50 percent (as opposed to 9.01 percent), assuming a 50 bps allowance for floatation costs.[466]

The CEC

The CEC notes that both experts agree that CAPM underestimates the cost of equity for smaller companies leading to a size premium adjustment for FBC. The CEC remarks that the BCUC has previously set the size premium for FBC at 40 bps higher than FEI, which is smaller than the Duff & Phelps table of size premiums would indicate. FortisBC suggests that Mr. Coyne's recommendations should be viewed as conservative. The CEC submits maintaining the FBC 40-bps adder continues to be appropriate and any further movement on the size premium is not necessary.[467]

FortisBC Reply Argument

FortisBC notes that, while BCOAPO acknowledges the need for a size premium for FBC, it recommends an amount far less than the 105 bps calculated by Mr. Coyne based on Duff & Phelps. FortisBC states that

[460] FortisBC Final Argument, para. 359, p. 177.
[461] Ibid., para. 244(f), p. 122.
[462] Ibid., para. 364, p. 179.
[463] Ibid., para. 365, p. 180.
[464] BCOAPO Final Argument, p. 55.
[465] Ibid.
[466] Ibid., p. 58.
[467] The CEC Final Argument, pp. 55–56.

BCOAPO's own calculations suggest an implicit size premium of 46 bps, but when considering a mathematical error made by BCOAPO, the implicit size premium is reduced to 21 bps.[468]

Panel Determination

Both experts agree that smaller firms tend to have higher returns than predicted by application of the CAPM. We also note that Mr. Coyne does not propose to adjust his FBC CAPM results to reflect a size premium. However, we note that FortisBC submits that the BCUC should find that Mr. Coyne's CAPM results for FBC are understated by a minimum of 40 bps and should consider a size premium for FBC, which is much smaller than the electric proxy group companies. The Panel will review the implications of the lack of a size premium in making its overall determination on the capital structure and ROE for FBC in Section 6.3 (Overall Capital Structure and ROE).

5.2.5 Overall CAPM Results

In Section 5.2.1, the Panel finds that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable. In Section 5.2.2, the Panel accepts Mr. Coyne's beta estimates for the proxy groups. In Section 5.2.3, the Panel concludes it can place little weight on the two-stage forward-looking MRP model derived by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach. Accordingly, this section reviews Mr. Coyne's October 2022 proposed CAPM ROE and intervener submissions regarding these results.

Consistent with the Panel's earlier determination to use the most current data, the table below summarizes Mr. Coyne's CAPM results based on the October 2022 data.

Table 16: CAPM ROE Results (excluding floatation costs)[469]

October 2022	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
Mr. Coyne	9.62%	9.46%	9.80%	10.01%	9.74%

Mr. Coyne's results reflect his approach of using a forecast bond yield for the risk-free rate, Blume-adjusted betas, and an MRP which consists of the average of Canadian and US historical and forward-looking MRPs with the latter derived using a constant DCF model. His results do not include a Hamada adjustment to account for the difference in leverage between the utilities under review and the proxy group companies.

FortisBC submits that the anomalous CAPM results produced by Mr. Coyne using his interpretation of Dr. Lesser's preferred inputs serve as a reminder of the importance of the BCUC considering models holistically, rather than making discrete decisions on model elements or inputs in a vacuum. FortisBC emphasizes that for every modelling decision that Mr. Coyne made that participants have challenged because it directionally produced higher ROE results, there are examples where Mr. Coyne made decisions that had the opposite effect:

[468] FortisBC Reply Argument, p. 47.
[469] Exhibit B1-50, Table 3, Scenario A.2, p. 4.

- Did not add a Hamada adjustment to his CAPM modelling to account for the fact that FBC and FEI are both more highly leveraged than the proxy group companies. This was predicated on the common equity ratio proposal that would reduce the disparity between the allowed equity ratio for FEI with the proxy groups and retaining FBC's existing equity ratio;
- Did not add a 105-bps size premium to his CAPM results for FBC, despite both experts believing a ROE size premium is appropriate;
- Recommended forecast bond yields rather than actual bond yields, even though the former produces lower CAPM results based on October 2022 data; and
- Averaged the forward-looking MRP with the lower historical MRP to moderate the results, despite it also being theoretically valid to only use a forward-looking MRP (as does FERC).[470]

FortisBC cautions that "assessing each of Mr. Coyne's methodological decisions in isolation risks "cherry picking", producing a result that poorly reflects current market conditions and the forward-looking expectations of investors.[471]

Positions of Parties

ICG

ICG's final argument is submitted on behalf of FBC's industrial customers and therefore, it is focused on issues of relevance to FBC only.[472] ICG submits that the BCUC should give no weight to Mr. Coyne's CAPM results and that the BCUC should reject FortisBC's submission to not place any weight on the Lesser CAPM results.[473] Despite Mr. Coyne's testimony that the model inputs recommended by Dr. Lesser somehow affected the Concentric model to the point of affecting the functionality of the model, ICG submits that the BCUC should dismiss this notion and can rely on the model results once it has determined the appropriate inputs to the model.[474]

Regarding the recommended ROE for FBC, ICG submits:[475]

> Dr. Lesser's Average CAPM and Multi-Stage [sic] DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates) is 8.3% ROE.[36]
>
> Footnote 36: Exhibit B1-50, p. 9, Figure 10

Based on ICG's overall ROE recommendation above, it is possible to separately identify ICG's recommended CAPM ROE. In the main body of ICG's submission, ICG references, "Dr. Lesser's […] CAPM results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates)". This specific scenario results in an ROE of 7.60 percent.[476] However, the text in footnote 36 references a different

[470] FortisBC Final Argument, para. 265, pp. 133–134.
[471] FortisBC Final Argument, para. 266, p. 134.
[472] ICG Final Argument, p. 3.
[473] Ibid.
[474] Ibid., p. 10.
[475] Ibid., para. 33, p. 15.
[476] Exhibit B1-50, Scenario B.6, Figure 12, p. 10.

scenario, that of Dr. Lesser's December 2021 data (90-day average stock prices and interest rates). This scenario results in an ROE of 7.50 percent.[477]

Therefore, before the flotation allowance adder, ICG recommends a CAPM ROE of 7.00 or 7.10 percent for FBC, depending on the scenario one looks at (October 2022 – 30 days versus December 2021 – 90 days) based on the North American proxy group.

BCOAPO

As previously explained in Section 3.2, BCOAPO modifies the composition of the North American proxy group. BCOAPO recalculates revised CAPM ROE estimates by removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group and Canadian Utilities Limited from the North American electric proxy group, as these utilities would not pass Mr. Coyne's screening criteria.[478] BCOAPO then averages its own recalculated Coyne – CAPM and Lesser – CAPM to derive its CAPM ROE results, shown in Table 17 below.

Table 17: BCOAPO - Summary of CAPM ROE – October 2022 (90 Trading Days)[479]

Average CAPM Results (*i.e.* average of historic and forward-looking MRP) * Results include the 50-bps flotation costs			
BCOAPO-Revised Proxy Group	Coyne-Average CAPM as revised by BCOAPO	Lesser-Average CAPM *as revised by BCOAPO*	BCOAPO recommended CAPM
North American Gas Utilities	10.40%	8.86%	**9.63%**
North American Electric Utilities	10.27%	8.75%	**9.01%**

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 18 shows the results without the adder.

Table 18: BCOAPO - Summary of CAPM ROE – October 2022 (90 Trading Days)[480]

Average CAPM Results (*i.e.* average of historic and forward-looking MRP) * Results exclude the 50-bps flotation costs			
BCOAPO-Revised Proxy Group	Coyne-Average CAPM as revised by BCOAPO	Lesser-Average CAPM *as revised by BCOAPO*	BCOAPO recommended CAPM
North American Gas Utilities	9.90%	8.36%	**9.13%**
North American Electric Utilities	9.77%	8.25%	**8.51%**

The CEC

The CEC submits that the BCUC should give significant weight to Mr. Coyne's CAPM and not use the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's approach in its determinations. The CEC states there

[477] Exhibit B1-50, Scenario B.6, Figure 10, p. 9.

[478] BCOAPO Final Argument, pp. 52–53.

[479] Ibid.

[480] Table created from Table 17 figures with 50 bps subtracted.

are questionable assumptions, and the results are too far away from a reasonable level as noted even by Dr. Lesser. Additionally, the CEC is satisfied that the differences between the two CAPM models have been explained and that they do not arise from model flaws but from differences in input data used and/or the specific selected treatment of the input data.[481]

The CEC uses Mr. Coyne's CAPM results (October 2022, 90 days) to derive its own ROE recommendation. The CEC recommends that the BCUC use the simple average of proxy groups to determine the appropriate ROE for FEI and FBC. Before adjustments, the CEC calculates an ROE of 10.127 percent for FEI and 10.29 percent for FBC as shown in Table 19.

Table 19: CEC's Recommended ROE from the CAPM (including flotation costs)[482]

	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	10.12%	9.96%	10.30%	10.127%
Electric	10.12%	10.51%	10.24%	10.29%

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 20 shows the results without the adder.

Table 20: CEC's Recommended ROE from the CAPM (excluding flotation costs)[483]

	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	9.62%	9.46%	9.80%	9.627%
Electric	9.62%	10.01%	9.74%	9.79%

In conclusion, the CEC recommends that the BCUC acknowledge Mr. Coyne's decisions to adopt reasonably conservative positions on several issues and recommends that the BCUC also adopt a conservative approach.[484]

RCIA

RCIA remarks that Mr. Coyne's CAPM ROE estimates are higher than those obtained from Dr. Lesser's assumptions. As noted above, RCIA is particularly concerned with the parameters proposed in relation to the risk-free rate and the MRP.[485] Considering its specific submissions on those two inputs, RCIA recommends adjusting Mr. Coyne's CAPM. Using the mid-point of these adjustments, the result is an overall decrease of about 2.42 percent in the ROE as shown in Table 21. RCIA submits that the CAPM ROE should be 8.26 percent, not 10.68 percent, as suggested by Concentric.[486]

[481] The CEC Final Argument, pp. 37–38.
[482] Information in the table has been compiled from the CEC Final Argument, p. 43.
[483] Table created from Table 19 figures with 50 bps subtracted.
[484] The CEC Final Argument, p. 42.
[485] RCIA Final Argument, pp. 10–11.
[486] Ibid., p. 20.

Table 21: RCIA - Adjustment to Recommended ROE using CAPM

Correction	Impact on ROE	Mid-Point
Using actual bond yields for risk-free rate	-0.68% to -1.04%	-0.86%
Using only Canadian MRP data	-0.77%	-0.77%
Using 75:25 blend of historical & forecast MRP	-0.79%	-0.79%
Total	**-2.24 to -2.60%**	**-2.42 %**

FortisBC Reply Argument

Regarding ICG's recommendation to use the CAPM results using Dr. Lesser's approach, FortisBC submits:

- This CAPM result that ICG is using in its calculation is 7.10 percent (or 7.60 percent after inclusion of flotation cost), which is a number well below what even Dr. Lesser considers reasonable and not far removed from the cost of debt; and
- ICG did not account for any size premium for FBC, even though the experts agree that the CAPM understates ROE results for firms like FBC that are smaller than the proxy companies.[487]

FortisBC also points out the straightforward mathematical error that BCOAPO made in averaging the results of its CAPM calculations for its adjusted North American proxy group.

FortisBC submits that RCIA introduces unsupported CAPM adjustments, uses stale data, and omits Hamada and size adjustments. For illustration purposes only, FortisBC proceeds to apply RCIA's above downward adjustments to the October 2022 data, since both experts note the appropriateness of using the most recent data and RCIA did not say why it disregarded that data. Mr. Coyne's October 2022 CAPM results for the Canadian proxy group is 10.12= percent. [488] Using actual bond yields will increase CAPM results by 6 to 42 bps with a mid-point of 24 bps while using 75:25 Canadian-only historical and forward-looking MRP will decrease the October 2022 CAPM results by 93 bps. Overall, the downward adjustment would be 69 bps on 10.12 percent (=9.43%[489]), instead of the -2.42 percent on 10.68 percent (=8.26%).[490] FortisBC submits that RCIA's own calculations, properly updated for October 2022 data reinforce Mr. Coyne's recommendations, which is a full answer to RCIA's argument that Mr. Coyne's analysis is biased.[491]

Panel Determination

With respect to the CAPM results, previously in this Decision, the Panel determined that:

- Using the most up-to-date data (i.e. October 2022 data) is appropriate;

[487] FortisBC Reply Argument, pp. 55–56.
[488] Including a 50-bps adder for flotation cost and financial flexibility.
[489] Including a 50-bps adder for flotation cost and financial flexibility.
[490] FortisBC Reply Argument, p. 50.
[491] Ibid., p. 53.

- Mr. Coyne's October 2022 estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable;
- Mr. Coyne's sources and averaging of adjusted data to estimate betas for the proxy groups are acceptable;
- Mr. Coyne's approach to addressing the differences in financial leverage in the proxy group companies through adjustments to the capital structure is acceptable and consistent with how the BCUC typically accounts for relative risk;
- Mr. Coyne's 50:50 weighting of historic and forward MRPs is an appropriate and sufficient balance between the assumption that higher analyst expectations over the next five years are expected to continue into the future and the actual achieved MRPs over a long history; and
- We place no reliance on the two-stage MRP estimate prepared by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach.

Since we are not relying on the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's approach, we agree with FortisBC that we should not be adjusting the CAPM results in the manner suggested by BCOAPO. For the same reason, we also disregard ICG's CAPM submissions. Given the Panel determines that it should be using the October 2022 data to inform the establishment of an appropriate ROE, we agree with FortisBC's comments related to RCIA's use of "stale data". Regarding RCIA's suggestion to use a 75:25 blend of historic and forecast MRP, we note our determination that a 50:50 weighting strikes an appropriate balance. However, for reasons previously expressed, we disagree with FortisBC's characterization that the use of historical data as being conservative. As previously noted, the Panel will consider the implications of the lack of a size adjustment in the CAPM results in determining the specific weight to be accorded the various ROE models in Section 6.3 (Overall Capital Structure and ROE).

In Section 3.2 above, the Panel determines that the appropriate proxy groups to use for FEI and FBC are the North American gas and electric proxy groups, which should be revised in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which are unlikely to have passed Mr. Coyne's screening criteria if applied strictly.

Table 22 shows the detail of Mr. Coyne's North American gas proxy groups CAPM results. Removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group yields a revised calculated average ROE of 9.90 percent compared to the 9.80 percent proposed by Mr. Coyne,[492] excluding an adder for flotation costs and financial flexibility.

[492] Calculated by the BCUC using the Average function in Excel = Average (11.69%,10.03%,9.05%,9.39%,9.35%) = 9.90%.

Table 22: CAPM - North American Gas Utilities[493]

North American Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
AltaGas Inc.	ALA	1.16	n/a	1.16	3.21%	7.29%	11.69%	0.50%	12.19%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.21%	7.29%	9.37%	0.50%	9.87%
Enbridge Inc.	ENB	0.93	0.85	0.89	3.21%	7.29%	9.72%	0.50%	10.22%
New Jersey Natural Resources	NJR	0.84	0.95	0.90	3.50%	7.29%	10.03%	0.50%	10.53%
Northwest Natural Gas Company	NWN	0.72	0.80	0.76	3.50%	7.29%	9.05%	0.50%	9.55%
ONE Gas, Inc.	OGS	0.82	0.80	0.81	3.50%	7.29%	9.39%	0.50%	9.89%
Spire, Inc.	SR	0.81	0.80	0.80	3.50%	7.29%	9.35%	0.50%	9.85%
MEAN		0.88	0.84	0.88			9.80%		10.30%

Table 23 shows the detail of Mr. Coyne's North American electric proxy groups CAPM results. Removing Canadian Utilities Limited from the North American electric proxy group yields a revised calculated average ROE of 9.77 percent compared to the 9.74 percent proposed by Mr. Coyne,[494] excluding any adjustment for a size premium and an adder for flotation costs and financial flexibility.

Table 23: CAPM - North American Electric Utilities[495]

North American Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power and Utilities	AQN	0.99	n/a	0.99	3.21%	7.29%	10.46%	0.50%	10.96%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.21%	7.29%	9.37%	0.50%	9.87%
Emera Inc.	EMA	0.69	0.75	0.72	3.21%	7.29%	8.45%	0.50%	8.95%
Hydro One, Ltd.	H	0.66	n/a	0.66	3.21%	7.29%	8.03%	0.50%	8.53%
Alliant Energy Corporation	LNT	0.86	0.85	0.85	3.50%	7.29%	9.72%	0.50%	10.22%
American Electric Power Company, Inc.	AEP	0.82	0.75	0.79	3.50%	7.29%	9.23%	0.50%	9.73%
Duke Energy Corporation	DUK	0.80	0.85	0.82	3.50%	7.29%	9.50%	0.50%	10.00%
Entergy Corporation	ETR	0.94	0.95	0.94	3.50%	7.29%	10.39%	0.50%	10.89%
Exelon Corporation	EXC	0.95	NMF	0.95	3.50%	7.29%	10.42%	0.50%	10.92%
Evergy Inc	EVRG	0.87	0.90	0.89	3.50%	7.29%	9.96%	0.50%	10.46%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.50%	7.29%	10.19%	0.50%	10.69%
OGE Energy Corporation	OGE	0.99	1.05	1.02	3.50%	7.29%	10.94%	0.50%	11.44%
Pinnacle West Capital Corporation	PNW	0.90	0.90	0.90	3.50%	7.29%	10.07%	0.50%	10.57%
Portland General Electric Company	POR	0.84	0.85	0.84	3.50%	7.29%	9.65%	0.50%	10.15%
MEAN		0.86	0.88	0.87			9.74%		10.24%

Therefore, the Panel will consider a CAPM ROE, exclusive of an adder for flotation costs and financial flexibility of 9.90 percent for FEI and 9.77 percent for FBC as it weights the different ROE models (see Section 6.3).

5.3 Discounted Cash Flow Approach

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected cash flows over time. The standard DCF model is shown in Equation (3):[496]

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad (3)$$

Where:

P = the current stock price

g = the dividend growth rate

Dn = the dividend in year n

r = the cost of common equity

[493] Exhibit B1-50, Attachment A.2 FEI – Gas (Oct 2022 update 90 day), Tab JMC-FEI-6.1 Avg CAPM.

[494] Calculated by the BCUC by averaging the following figures: 10.46%, 8.45%, 8.03%, 9.72%, 9.23%, 9.50%, 10.39%, 10.42%, 9.96%, 10.19%, 10.94%, 10.07% and 9.65%.

[495] Exhibit B1-50, Attachment A.2 FBC – Electric (Oct 2022 update 90 day), Tab JMC-FBC-8.1 Avg CAPM.

[496] Exhibit B1-8-1, Appendix C, p. 48.

Applying the DCF methodology to solve Equation (3) for the cost of equity, *r*, one can determine the discount rate that equates the discounted present value of those future dividend payments to the stock's price today. Thus, the DCF methodology can be thought of as a stock valuation exercise in reverse. Assuming a constant growth rate in dividends, the equation can be rearranged to compute the ROE as shown in Equation (4):[497]

$$r = \frac{D}{P} + g \qquad (4)$$

Stated otherwise, the cost of equity is equal to the dividend yield (D/P) plus the expected dividend growth rate.[498] This DCF model, known as the Constant Growth DCF Model, requires several assumptions: (1) a constant average growth rate for dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Dr. Lesser states that the advantage of the Constant Growth DCF model is its simplicity; however, this simplicity is also a disadvantage of the model because it assumes that short-term growth rates continue forever.[499] An alternative to the Constant Growth DCF model is the Multi-Stage DCF model, which tempers the assumption of constant dividend growth in perpetuity with a multi-stage dividend growth rate. Dr. Lesser states that "the rationale for using a multi-stage DCF model is that high short-term growth rates cannot persist forever. As firms increase in size, their markets become saturated, and thus their growth slows."[500] The Multi-Stage DCF model was the BCUC's preferred DCF model in the last two cost of capital proceedings.[501] Even though Mr. Coyne presents the results of the Constant Growth DCF model, he recommends the use of a multi-stage DCF model that employs three stages for dividend growth; near-term, transitional, and long-term growth rates (see Section 5.3.2). Dr. Lesser also confirms his preference for a Multi-Stage DCF model over Constant Growth DCF because long-term earnings growth reverts to that of the economy as a whole.[502] Dr. Lesser discusses the merits of both a two-stage and a three-stage dividend growth rate model, without stating a preference.

Dr. Lesser explains that, like the CAPM, the DCF model will mis-estimate the cost of capital for a utility when there is a mismatch between the common equity ratio of the subject utility and the common equity ratios of the peer group used:[503]

> When setting an allowed ROE value for a regulated utility, the resulting WACC [weighted average cost of capital] value may not reflect risk comparability if the capital structure of the regulated utility under review differs from those of the proxy group. For example, if the average capital structure of the proxy group is 50% equity and 50% debt, while the subject utility has a capital structure of 25% equity and 75% debt, then because the subject utility has more financial risk, equity investors will require a higher expected return.

FortisBC points out that Mr. Coyne "[d]id not perform a WACC adjustment to the Multi-Stage DCF results […] to account for the fact that FBC and FEI are both more highly leveraged than the proxy group companies. This was

[497] Exhibit B1-8-1, Appendix C, p. 48.
[498] Ibid.
[499] Exhibit A2-3, p. 30.
[500] Ibid., p. 29.
[501] Exhibit B1-8-1, Appendix C, pp. 52–53.
[502] Exhibit A2-5, BCOAPO IR 3.1.
[503] FEI Final Argument, p. 174.

predicated on the common equity ratio proposal that would reduce the disparity between the allowed equity ratio for FEI with the proxy groups and retaining FBC's existing equity ratio."[504]

The following sub-sections discuss the determination of the dividend yield and the dividend growth rate.

5.3.1 Dividend Yield

The first term in Equation (4) is the dividend yield, which has two key drivers. The first driver is the selection of the proxy group, and the second is the historic time period used to gather stock prices data for the respective companies in the proxy group. Mr. Coyne calculates the dividend yields for each company in his five proxy groups[505] by dividing the current annualized dividend by the average stock price for each company. Those dividend yields are multiplied by one-half the dividend growth rate to account for increases in quarterly dividends at different times throughout the year as shown in Equation (5).[506] Dr. Lesser also supports adjusting the current dividend yield by 0.5 times the growth rate.[507]

$$Y = \frac{D}{P} = \frac{D_0(1 + 0.5g)}{P_0} \qquad (5)$$

Mr. Coyne uses a 90-trading day average for stock prices to calculate the dividend yield for proxy group firms in both his December 2021 evidence and his September 2022 Update. The latter resulted in lower Multi-Stage DCF results across the board relative to the former.[508] Reflecting on these results, Concentric states:

> Under normal market circumstances, Mr. Coyne would accept these results as determinative, but substantially higher interest rates and sustained higher inflation levels do not indicate a reduction in the cost of equity -- this is not an intuitive result. Markets have been anything but normal in 2022. […] Contributing to this capital market turmoil, inflation in both the US and Canada is running at levels not seen since the early 1980s. In previous periods of market disruption, utilities have served as a safe haven for investors, but as explained in a *Wall Street Journal* article this week, that has not been the case recently.[509] [*Emphasis added*]

The *Wall Street Journal* article explains that, while utility stocks were among the best-performing segment of the market in the early part of 2022, they became the worst-performing sector of the S&P 500 in the period mid-September 2022 to mid-October 2022, as the sizable dividends of utility stocks (among the highest payout percentages in the index at 3.3 percent) were no match for climbing bond yields reaching four percent in mid-October 2022.[510]

Mr. Coyne explains that these market circumstances require an examination of the models and inputs used for estimating the cost of capital and the application of informed judgment. With respect to the DCF model, Mr. Coyne expresses the following concern:

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[504] FEI Final Argument, p. 134.
[505] Canadian utilities, US gas utilities, US electric utilities, North American gas utilities, and North American electric utilities.
[506] Exhibit B1-8-1, Appendix C, p. 49.
[507] Exhibit A2-3, p. 27.
[508] Exhibit B1-8-1, Appendix C, p. 49, Exhibit B1-8-1-2, Footnote 1, p. 2, FortisBC Final Argument, para. 303, pp. 150–151.
[509] Exhibit B1-8-1-2, p. 4.
[510] Ibid., pp. 4–5.

> Utility stock prices, as indicated in the above article, have responded slowly to the down market in 2022, so the 90-day historic stock price averages used in the DCF model are not reflective of current market conditions.[511] [*Emphasis added*]

To test this hypothesis, Mr. Coyne replaced the 90-trading day average stock prices with the current stock prices (Spot Price) in his September 2022 Update and when doing so, the Multi-Stage DCF Model results shift back to those estimated in December 2021.[512]

While both experts agree with the use of recent average stock prices in calculating the dividend yield in the DCF Model[513], an area of debate emerged at the oral hearing regarding the appropriate period to use for this exercise in the current economic context. At the oral hearing, Dr. Lesser acknowledged that he may use shorter periods depending on "what's happened in the market", though not shorter than 30 days.[514] FortisBC states that this is consistent with what Dr. Lesser had done in two proceedings from 2002 (he used 30 days in one and 60 days in the other) in circumstances that he had characterized as being influenced by the threat of war, emerging from challenging economic circumstances and unprecedented monetary policy intervention. FortisBC argues that the extraordinary conditions earlier in 2022 are not dissimilar to the conditions highlighted by Dr. Lesser in 2002 and they, too, give rise to concerns that older data are not reflective of investors' forward-looking expectations.[515]

5.3.2 Dividend Growth Rates

The second term (*g*) of Equation (4)[516] is the dividend growth rate, which has two key attributes. The first attribute is the number and duration of the stages of growth, and the second is the basis of the dividend growth for each stage.

5.3.2.1 Number and Duration of the Stages of Growth

Mr. Coyne adopts a three-stage DCF model that employs the following values for the duration and the basis of the dividend growth for each stage:

a) First stage (Years 1 to 5): Near-term growth as measured by analysts' EPS growth projections used in the Constant Growth DCF Model;

b) Second (transitional) stage (Years 6 to 10): Connects near-term with long-term growth by changing the growth rate each year on a pro rata basis; and

c) Third (perpetuity) stage (Years 11 and beyond): Long-term forecast of nominal GDP growth, which is estimated based on estimates of real GDP growth rate and inflation by *Consensus Economics*.[517]

[511] Exhibit B1-8-1-2, p. 5.
[512] Ibid., p. 6.
[513] Transcript Volume 3, p. 161, Lines 2–4.
[514] Transcript Volume 4, p. 440, Lines 20–24.
[515] FortisBC Final Argument, para 305, p. 151.
[516] Equation (4) is a simplified equation where the dividend growth rate is constant. In a Multi-Stage DCF, the dividend growth rate takes different values for the different stages used in the model.
[517] Exhibit B1-8-1, Appendix C, p. 53.

Dr. Lesser supports Mr. Coyne's approach: "[f]or a multi-stage DCF model, I agree with Mr. Coyne that the most typical approach is to assume an initial stage lasting five years. […] Mr. Coyne's three-stage model is certainly one approach that is sometimes used, and a five-year middle stage is not unreasonable."[518]

5.3.2.2 Basis of the Dividend Growth for Each Stage

Analysts' forecasts in First Stage

In considering the appropriate basis for the growth rate for the first stage in the Multi-Stage DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. Mr. Coyne explains that investors rely on projected earnings growth rate rather than dividend growth rates because 1) a company's dividend growth is derived and can only be sustained by earnings growth; 2) earnings growth rates are less influenced by dividend decisions; and 3) analysts' forecast of earnings growth are more widely available than dividend forecasts.[519]

Echoing point 1 above, Dr. Lesser states that "because earnings are the ultimate source of dividends – a firm cannot continue to pay dividends if it has no earnings – the growth rate term *g* used in [Equation (4)] is almost always the forecast growth in earnings."[520] Thus, the two experts agree that dividend growth rates should be estimated using earnings growth rates.

Mr. Coyne and Dr. Lesser also agree that analysts' estimates are the appropriate source for forecast earnings growth rates but disagree on which data sources to use for the first stage. Earnings growth rates are forecast by stock analysts typically for periods of three to five years but how those analysts develop their forecasts is not publicly known.[521] Mr. Coyne relies on earnings growth estimates from four data sources: SNL Financial, Value Line, Zacks and Thomson First Call for the companies in the proxy groups.[522] In contrast, Dr. Lesser supports the use of a single source of earnings growth rate forecasts using the Institutional Brokers' Estimate System (IBES) earnings growth rates published by Yahoo!Finance.

Mr. Coyne explains that Yahoo!Finance, Zacks, and SNL Financial are all consensus forecasts, which means these sources gather consensus of the equity analysts that cover these companies, and then they report out the consensus view from those individual analysts.[523] Mr. Coyne states that "[o]ne benefit of averaging four sources is that you get to mitigate the impact of anyone that will differ from another. And there can be some substantial differences, and I would be very concerned with just using one source."[524] Mr. Coyne further states that the EPS growth rates reported by Yahoo!Finance are not always updated on a regular basis such that they may become stale at times, and Yahoo!Finance does not provide EPS growth rates for every Canadian utility company, so it is necessary to also consider other sources such as Zacks Investment Research, Value Line, and SNL Financial to

[518] Exhibit A2-20, BCUC IR 5.4.
[519] Exhibit B1-8-1, Appendix C, pp. 49–50.
[520] Exhibit A2-3, p. 27.
[521] Ibid., p. 31.
[522] Exhibit B1-8-1, Appendix C, p. 49.
[523] Transcript Volume 3, p. 314.
[524] Ibid., pp. 314–315.

develop a more robust DCF analysis for a Canadian proxy group.[525] However, Mr. Coyne confirms that there is coverage by Yahoo!Finance on the Canadian proxy group and submits that it is not an issue at this time.[526]

Dr. Lesser supports the use of a single source of earnings growth rate forecasts,[527] stating, "I do not consider averaging different earnings growth rates to be reasonable because they do not necessarily reflect the same time periods and forecast duration. Also, I prefer, as does FERC, to rely on the IBES earnings growth rates published by Yahoo!Finance because they are available publicly."[528] Dr. Lesser further states that FERC has expressed concerns about mixing and matching earnings growth rates because 1) the analysts are using different methodologies and different time periods and 2) the analysts are using proprietary growth rates to which no one else can have access to.[529] Dr. Lesser also notes that "simply taking an average as Mr. Coyne suggests, that may be reasonable. But if you're taking an average of say someone's result that's unreasonable, […] you may just be baking in an unreasonable value."[530]

The difference between using a single or multiple data sources for the earnings growth rate forecasts was shown to be immaterial, early in the proceeding, when Mr. Coyne re-ran his Multi-Stage DCF model by replacing his earnings growth rate forecast with Dr. Lesser's recommended earnings growth rate forecast based on the IBES earnings growth rates published by Yahoo!Finance based on December 2021 data. For the US gas proxy group, the Multi-Stage DCF ROE decreased from 9.53 percent[531] to 9.44 percent[532] and for the US electric proxy group, the Multi-Stage DCF ROE increased from 8.82 percent[533] to 8.91 percent[534].

GDP growth rate in Second Stage

As noted above, the second stage is a transitional stage that connects near-term with long-term growth by changing the growth rate each year on a pro rata basis. Thus, the GDP growth rates in this stage are derived mathematically and no parties raised issues with this calculation during the hearing.

GDP growth rate in Third Stage

The experts also disagree on the method to calculate the perpetuity GDP growth rate in Stage 3 of the Multi-Stage DCF model. Mr. Coyne calculates the perpetuity GDP growth rate based on GDP and the Consumer Price Index (CPI). Dr. Lesser disagrees with this calculation method and suggests the proper way to convert real GDP growth rate forecast to a nominal one is to use the GDP implicit price deflator. The difference between the CPI and the GDP implicit price deflator is that the CPI is the consumer price index, so it measures inflation for a market basket of consumer goods, whereas the GDP implicit price deflator measures the overall inflation rate of the entire economy.[535] Dr. Lesser further states that using the CPI will overestimate the ROE but admits that "in

[525] Exhibit B1-21, Part 2, p. 11.
[526] Transcript Volume 3, p. 323.
[527] Exhibit A2-3, p. 32.
[528] Exhibit A2-24, BCOAPO IR 17.2.
[529] Transcript Volume 3, p. 318.
[530] Transcript Volume 3, p. 318.
[531] Exhibit B1-8-1, Appendix C, Figure 1, p. 4 (inclusive of a 50-bps adder).
[532] Exhibit B1-25, BCUC IR 3.1.2, Revised Figure 1 (inclusive of a 50-bps adder).
[533] Exhibit B1-8-1, Appendix C, Figure 2, p. 5 (inclusive of a 50-bps adder).
[534] Exhibit B1-25, BCUC IR 3.1.2, Revised Figure 2 (inclusive of a 50-bps adder).
[535] Transcript Volume 3, pp. 261–262.

terms of all the other inputs to the analyses, that whether it's the CPI or the GDP deflator is probably not going to be the determining factor in setting an allowed ROE".[536]

In response, Mr. Coyne notes that he doesn't disagree with Dr. Lesser and if he was looking at historic data on GDP growth rate, he would use the same method as Dr. Lesser. However, since the GDP growth rate is a forecast, Mr. Coyne submits that he prefers to use forecast inflation data and that he is constrained by the available data, as *Consensus Economics* does not forecast the implicit price deflator.[537]

The evidence on record in this proceeding only includes Multi-Stage DCF ROE results where the perpetuity GDP growth rate is based on the GDP and CPI.

5.3.3 Overall Multi-Stage DCF Model Results

The next two sub-sections will present Mr. Coyne's DCF results based on the most recent October 2022 results, consistent with our determination above in Section 3.3 to use the most recent data.

5.3.3.1 Constant Growth DCF Model

Even though Mr. Coyne uses the results of the Multi-Stage DCF model in his ROE recommendation for FEI and FBC, he also presents the results of the Constant Growth DCF Model. Mr. Coyne's results have been revised to exclude the 50-bps adder for flotation costs and financial flexibility as shown in Table 24 below.

Table 24: Mr. Coyne's Constant Growth DCF ROE Results[538]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 90 trading days[539]	11.48%	9.31%	10.45%	9.17%	9.59%
October 2022 – 30 trading days[540]	11.85%	9.57%	10.72%	9.48%	9.94%

5.3.3.2 Multi-Stage DCF Model

Table 25 below presents Mr. Coyne's Multi-Stage DCF results based on the October 2022 data, using different historic time periods for stock prices to calculate the dividend yields. Those results reflect Mr. Coyne's approach of using four data sources for the earnings growth rates and a perpetuity GDP growth rate based on GDP and CPI. The results have been modified to exclude the 50-bps adder for flotation costs and financial flexibility that Mr. Coyne included in his results.

[536] Transcript Volume 3, p. 264.
[537] Ibid., p. 262.
[538] Information in the table is taken from the referenced footnotes within the table.
[539] Exhibit B1-50, Figures 3 and 4, Scenario A.2, p. 6.
[540] Ibid., Figures 5 and 6, Scenario A.3, p. 7.

Table 25: Mr. Coyne's Multi-Stage DCF ROE Results[541]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 90 trading days[542]	9.96%	8.44%	9.22%	8.24%	8.61%
October 2022 – 30 trading days[543]	10.43%	8.74%	9.53%	8.60%	9.02%

FortisBC points out that both experts agree on the merits of using the Multi-Stage DCF model.[544] FortisBC also states that it is aligned on the key aspects of the Multi-Stage DCF analysis and that Dr. Lesser's Multi-Stage DCF results are identical to Mr. Coyne's results.[545]

FortisBC also notes that Mr. Coyne presented the results of the Constant Growth DCF model, as it "was developed to estimate the cost of equity for dividend-paying companies in mature industries with steady and predictable growth rates, such as public utilities." FortisBC states that the results of this model tend to exceed the multi-stage DCF results because the EPS growth rates of the proxy companies are not constrained to equal GDP growth after 10 years. FortisBC explains that the experts debate whether a company's EPS can exceed GDP growth forever; however, the data demonstrates that EPS for the proxy utilities have grown faster than GDP for the 2005 to 2019 period. In FortisBC's view, the implication of this evidence for the BCUC is that these two models – the multi-stage DCF and the Constant Growth DCF – are both useful, but imperfect indicators of an estimated range of investors' expected returns. FortisBC submits that Mr. Coyne is being conservative in basing his ultimate recommendations on his Multi-Stage DCF model results, rather than a blend of the two DFC models.[546]

FortisBC remarks that Dr. Lesser had, in past testimony, given equal weight to the two DCF models, despite having the same theoretical reservation about the ability of a company's EPS to grow faster than GDP forever. While he has since changed his approach, FortisBC submits that the logic he had applied still has merit. His stated rationale had related to the benefits of having additional data points in the prevailing conditions, characterized by economic uncertainty, unprecedented actions by central banks and the threat of war abroad, all of which are present today.[547]

Regarding the preferred proxy groups, as noted earlier, FortisBC states that, even though Mr. Coyne developed his initial recommendation based on the results of his US proxy groups, the evidence on the record indicates that it would be appropriate for the BCUC to give primary weight to results based on Mr. Coyne's North American gas and electric proxy groups.

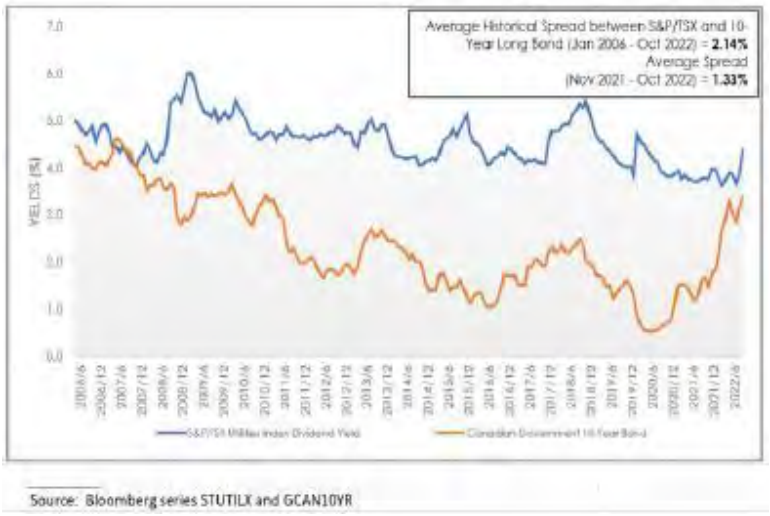
[541] Information in the table is taken from the referenced footnotes within the table.
[542] Exhibit B1-50, Table 2, Scenario A.2, p. 3.
[543] Ibid.
[544] FortisBC Final Argument, p. 136.
[545] Ibid., p. 122.
[546] FortisBC Final Argument, pp. 136–137.
[547] Ibid., p. 137.

Dividend Yield

With respect to using 30-day versus 90-day dividend yield data,[548] FortisBC submits that, while using 90-day data is normally reasonable, it may still be skewing the DCF results downwards. While the Efficient Market Hypothesis would suggest current prices are a better indicator of investors' expectations than past data, FortisBC recognizes that both experts agree that it is reasonable to use longer periods as a pragmatic means of moderating daily volatility in stock prices and dividend yields. Nonetheless, FortisBC submits that when interpreting the October 2022 results, the BCUC should consider the 90-day results but also recognize the tendency of a longer period like 90 days to understate investors' expectations due to the lingering effects of extraordinary events earlier in 2022.[549]

To support its position, FortisBC recalls that the six Bank of Canada interest rates increases between January 2022 and the oral hearing, with one more in December 2022, for a total increase of four percent in 2022. As a result, investors' expectations of dividend yields at the end of 2022 would bear little resemblance to what they were prior to the unprecedented increase in interest rates. FortisBC notes that, intuitively, dividend yields on utility stock must be higher than government bond yields to attract investment because utility stocks are higher risk. FortisBC presents a graph showing the statistically significant correlation over time between dividend yields and government bond yields, as shown below, with the notable exception of the summer 2022 when the spread had narrowed. In FortisBC's view, the narrowing spread is evidence that the market took some time to respond to the dramatic change in interest rates and government bond yields.[550]

Figure 2: S&P/TSX Utilities Index Dividend Yield versus Canadian Government 10-Year Bond Yields[551]



FortisBC states that the timing of the September 2022 Update, in conjunction with the use of a 90-trading day period, coincided with the transitory period of suppressed dividend yields and produced much lower results than Mr. Coyne's original analysis based on December 2021 data. FortisBC also notes that Mr. Coyne's October

[548] FortisBC notes that Mr. Coyne refers to "trading days" in his analysis such that "90-day" means 90 trading days and would be slightly more than 4 calendar months.

[549] FortisBC Final Argument, p. 150.

[550] FortisBC Final Argument, pp. 151–153.

[551] Exhibit B1-43; FortisBC Final Argument, p. 153.

2022 Update shows higher results compared to the September 2022 Update.[552] FortisBC cites Mr. Coyne at the oral hearing who noted that "the DCF model is producing results that look more like they did back in December" and that "as you have seen over the course of the last month or so, we've seen them come back into closer alignment. So, it's beginning to correct."[553]

FortisBC references Mr. Coyne's sensitivity analysis to the time horizon used (30-trading days vs. 90-trading days), which shows that a shorter period consistently increases the Multi-Stage DCF results because the lagging data inherent in using a 90-trading day period is still suppressing the DCF results in October 2022. Comparing the 90-day and 30-day scenarios gives an indication that dividend yields were lower in August and September 2022 compared to October 2022 (see Table 25).[554]

FortisBC states that Mr. Coyne confirms that, while the BCUC should have regard to the outputs from December 2021, September 2022, and October 2022, "… at the end of the day I do think that the most current information is what you should probably place the greatest weigh on." However, FortisBC remarks that Mr. Coyne also encourages the BCUC to put the model outputs in context: "So it's been a year of adaptations and disruptions in capital markets. But I think that the point I was making is that you need to understand what's happening to capital markets in 2022 in order to be able to interpret the results we're getting from the models." FortisBC concludes that the BCUC should find that the October 2022 results are potentially understating the investor-required return.[555]

Dividend Growth Rates

Regarding the data sources for EPS growth rates, FortisBC submits that using multiple data sources is a sensible approach and there is a sound logic to relying on multiple data sources, as Mr. Coyne has done, rather than relying on a single source as advocated by Dr. Lesser. Mr. Coyne uses four sources, three of which are consensus forecasts[556] whereas Value Line is an independent analyst forecast. Citing Mr. Coyne, FortisBC states that the purpose of using EPS growth rates in the DCF analysis is to reflect investors' expectations, and investors have access to all these data sources when formulating those expectations. Using multiple forecasts also reduces the potential for anomalous data to influence the results. Finally, Mr. Coyne notes that IBES Yahoo, which Dr. Lesser prefers, had some coverage shortcomings for Canadian companies in the past, as well as times where updates lagged other sources. All these concerns are mitigated by using multiple sources.[557]

Furthermore, FortisBC argues that Dr. Lesser's rationale for sole reliance on IBES does not withstand scrutiny for several reasons. Amongst those, his stance is difficult to reconcile with his support of the Efficient Market Hypothesis, which contemplates that investors will make use of all available information. Also, FortisBC states that Dr. Lesser's concern about different forecast horizons is overstated. Three of the forecasts use a five-year horizon. While Value Line uses three to five years, Mr. Coyne explains that this is not materially different from

[552] FortisBC Final Argument, p. 153.
[553] Ibid., pp. 154.
[554] Ibid., pp. 154–155.
[555] FortisBC Final Argument, p. 155.
[556] Zacks, SNL Financial and Thompson First Call, which is synonymous with IBES and Yahoo.
[557] FortisBC Final Argument, pp. 147–148.

the others in practice and that, in any event, the Value Line estimates "are generally within the range of those other sources".[558]

Positions of Parties

ICG

Regarding the DCF model, ICG only comments on the use of a single versus four sources of information for EPS growth rates. ICG agrees that investors use all sources of information. For practical reasons, ICG submits that using either a single or four sources for such information is not material and both are consistent with the Efficient Market Hypothesis.[559]

Regarding the recommended ROE for FBC, ICG submits:[560]

> Dr. Lesser's Average CAPM and Multi-Stage [sic] DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates) is [sic] 8.3% ROE.[36]
>
> Footnote 36: Exhibit B1-50, p. 9, Figure 10

Based on ICG's above overall ROE recommendation, it is possible to separately identify ICG's recommended Multi-Stage DCF's ROE. In the main body of ICG's submission, ICG references "Dr. Lesser's […] Multi-Stage DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates)". This specific scenario results in an ROE of 9.52 percent.[561] However, the text in footnote 36 references a different scenario, that of Dr. Lesser's December 2021 data (90-day average stock prices and interest rates). This scenario results in an ROE of 9.14 percent.[562]

Therefore, before the flotation allowance adder, ICG recommends a Multi-Stage DCF ROE of 8.64 or 9.02 percent for FBC, depending on the scenario one looks at (October 2022 – 30 days versus December 2021 – 90 days) based on the North American proxy group.

BCOAPO

BCOAPO notes that both experts conclude that the Multi-Stage DCF model should be used for purposes of estimating the ROE.[563]

BCOAPO notes the two experts' general agreement on the appropriate average period to calculate the dividend yield: Mr. Coyne uses a 90-trading day period in both his evidence and the September 2022 Update, and Dr. Lesser advocates for a three- to six-month period with a preference for three months, noting that one month should be the absolute minimum. BCOAPO notes that Mr. Coyne presents results using stock prices determined

[558] FortisBC Final Argument , pp. 148–149.
[559] ICG Final Argument, p. 9.
[560] Ibid., para. 33, p. 15.
[561] Exhibit B1-50, Scenario B.6, Figure 12, p. 10.
[562] Ibid., Scenario B.5, Figure 10, p. 9.
[563] BCOAPO Final Argument, p. 42.

over both 30-trading days and 90-trading days for purposes of an undertaking filed after the oral hearing. BCOAPO remarks that the only difference in the inputs used for the DCF calculations based on a 30- versus 90-day trading basis is the stock prices used in each, which are on average lower in the 30-day calculation in all relevant proxy groups. BCOAPO notes that the annual dividend values growth rates are the same for both periods.[564] BCOAPO agrees with Mr. Coyne's assessment that "[w]e're in an environment where there's a lot of uncertainty about the future of the economy at this point in time in the near term," and with this in mind, BCOAPO submits that DCF calculations based on 90 trading days should be the primary focus of the BCUC's deliberations. BCOAPO adds that this view is further reinforced by the fact that analysts' estimates of earning growth used in the DCF calculation are not necessarily updated every 30 trading days.[565]

With respect to the sources that should be used for the earnings growth rate forecasts, BCOAPO finds the rationale provided by Mr. Coyne in his rebuttal evidence and oral testimony for using multiple earnings growth sources to be compelling and agrees with his approach on this issue.[566]

As explained in more detail in Section 3.2, BCOAPO revises Mr. Coyne's Multi-Stage DCF ROE results by removing the two Canadian utilities that would, in Mr. Coyne's view, not pass the same screening criteria that he used to screen the US firms. BCOAPO's results, from those revisions, are 8.63 percent and 8.57 percent (excluding a 50-bps adder for flotation costs and financial flexibility) for the North American gas and electric proxy groups, respectively. BCOAPO submits that the BCUC should use these revised DCF ROE results when determining FEI and FBC's ROEs.[567]

The CEC

The CEC submits that the BCUC should give significant weight to the Multi-Stage DCF model while not weighting the Constant DCF model into its decision-making but using it only qualitatively in forming its final ROE determinations for FEI and FBC.[568] Regarding the use of 30-day or 90-day data, the CEC notes that both experts agree that a longer period is more appropriate to moderate daily volatility in stock prices and dividend yields. Mr. Coyne has used 90 days (trading days) and Dr. Lesser said he has no objection to the 90 days but would prefer data from one to three months. The CEC submits that the 90-day period for the data is appropriate in the circumstances and the shorter 30-day perspectives can be used as judgement information should the BCUC find it relevant for a particular concern.[569]

Regarding the basis of the dividend growth in the first stage, the CEC notes that both experts agree that projected earning is appropriate for the DCF modelling rather than DPS or sustainable growth, but they disagree on the source of the earnings information, with Mr. Coyne preferring multiple sources and Dr. Lesser preferring a single source. The CEC submits that both Dr. Lesser's approach and Mr. Coyne's approach have merit and the BCUC could make use of them by weighting each of these approaches into the BCUC's judgment as opposed to trying to pick one over the other.[570]

[564] BCOAPO Final Argument, pp. 39–40.
[565] Ibid., p. 40.
[566] Ibid., p.41.
[567] BCOAPO Final Argument, pp. 43–44.
[568] The CEC Final Argument, p. 39.
[569] Ibid., paras. 313–314, p. 45.
[570] Ibid., paras. 311–312, pp. 44–45.

Overall, the CEC recommends that the BCUC gives substantial weight to the multi-stage DCF modelling from Dr. Lesser[571] but proceeds to only highlight key results from Mr. Coyne's updated summary analysis for his October 2022, 90 days average stock prices and interest rates. Before adjustments, the CEC calculates an ROE of 9.71 percent for FEI and 9.81 percent for FBC as shown in Table 26, which is derived based on a simple average of the three proxy groups' results.[572]

Table 26: CEC's Recommended ROE from the Multi-Stage DCF Model[573]

Multi-Stage DCF Model Results for:	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	10.46%	8.94%	9.72%	9.707%
Electric	10.46%	8.74%	9.11%	9.813%

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 27 shows the results without the adder.

Table 27: CEC's Recommended ROE from the Multi-Stage DCF Model[574]

Multi-Stage DCF Model Results for:	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	9.96%	8.44%	9.22%	9.207%
Electric	9.96%	8.24%	8.61%	9.313%

FortisBC Reply Argument

As BCOAPO, the CEC and ICG all rely on the Multi-Stage DCF model, FortisBC limits its reply to addressing discrete issues about the model's application: a) the averaging period for calculating the dividend yield and b) the number of data sources for the dividend growth rate.[575]

On the first issue, FortisBC reiterates that using 90-trading day dividend yields is reasonable but skews the results downwards. In response to BCOAPO's submission that 90 trading days "should be the primary focus" because of the market uncertainty, FortisBC agrees that 90 days should be the primary focus under normal market conditions, but the BCUC should recognize that a period that long is skewing the DCF results downwards in the current circumstances. FortisBC notes that it is a fact that interest rates increased by 2.25 percent during the 90-day period used for Mr. Coyne's September 2022 Update, plus another 1.25 percent in September and October 2022. Referring to data that FortisBC includes in its final argument (see Figure 2), FortisBC states that statistical data shows that dividend yields on utility stocks are generally higher than government bond yields, which is intuitive, as higher returns are necessary to attract investment with a higher risk profile. As Mr. Coyne explains in his September 22 Update, utility stock prices lagged the sharp interest rate increases and down

[571] The CEC Final Argument, para. 296, p. 42.
[572] Ibid., paras. 299–300, p. 43.
[573] Ibid.
[574] Table created from Table 26 figures with 50 bps subtracted.
[575] FortisBC Reply Argument, p. 59.

market in 2022, meaning that "90-day historic stock price averages used in the DCF model are not reflective of current market conditions."[576]

On the second issue, FortisBC states that only BCOAPO and the CEC address the source of analyst estimates in the DCF model and points to BCOAPO's agreement to using multiple sources. In response to the CEC's suggestion to give weight to both Mr. Coyne and Dr. Lesser's approaches, FortisBC points out that Dr. Lesser's preferred source (IBES or Yahoo!Finance) is already included as one of Mr. Coyne's sources (i.e. Thompson First Call). Thus, the CEC's approach would give double weight to IBES without a clear reason as to why.[577]

FortisBC also points out that RCIA did not discuss or rely on the Multi-Stage DCF model at all, which FortisBC considers a notable omission and a key reason why its overall recommended ROE is so low. FortisBC submits that RCIA's choice to disregard the Multi-Stage DCF model is untenable because: a) both experts embrace that model, which is based on sound financial theory; b) the DCF methodology is the most commonly used by US regulators; c) the BCUC has generally given significant weight to the Multi-Stage DCF model results; and d) both experts agree on almost all data inputs so that the BCUC can have a particularly high confidence in the results.[578]

Panel Determination

Consistent with the BCUC's preferred approach in the last two cost of capital proceedings, the Panel finds that a Multi-Stage DCF model is preferable to a Constant Growth DCF model. The Multi-Stage DCF model allows for recognition that the proxy utility companies' dividend growth rates may not perform the same in different time horizons.

The Panel accepts that the results from the Multi-Stage DCF model may be more conservative than those from the Constant DCF model, and notes that no interveners favoured the Constant DCF model. Thus, the Panel finds that considerable weight should be given to the use of a Multi-Stage DCF model the purposes of determining the appropriate ROE for FEI and FBC. The specific weight to be accorded the Multi-Stage DCF model in the respective ROEs will be discussed in Section 6.3. (Overall Capital Structure and ROE).

In its final submission, FortisBC states that both Mr. Coyne and Dr. Lesser are aligned on the key aspects of the Multi-Stage DCF analysis, and that the Lesser Multi-Stage DCF results are identical to Mr. Coyne's results. As part of an undertaking after the oral hearing, Mr. Coyne provides four Multi-Stage DCF model runs that he entitles "B.4 to B.7 – Lesser".[579] However, Mr. Coyne was not asked to change any of his Multi-Stage DCF model inputs to replace them with Dr. Lesser's preferred inputs.[580] Thus, three of the four "Lesser" model runs are merely duplicates of Mr. Coyne's model runs for December 2021, October 2022 (90-day) and October 2022 (30-day) and as a result, the model outputs are identical. Therefore, one cannot conclude that Dr. Lesser's Multi-Stage DCF model supports Mr. Coyne's Multi-Stage DCF ROE results, as there are effectively no "Lesser Multi-Stage DCF Results".

[576] FortisBC Reply Argument, pp. 59–60.
[577] Ibid., p. 61.
[578] Ibid., pp. 48–49.
[579] Exhibit B1-50, Table 2, p. 3.
[580] Ibid., p. 1 – see list of requested scenarios.

Having only Mr. Coyne's October 2022 Multi-Stage DCF model results, the Panel must then decide which input to use for the dividend yield (i.e. the number of days for the historic stock price average). With respect to the dividend growth rates, the Panel must first determine the appropriate number and duration of the stages of growth, and then the basis of the dividend growth for each stage.

The Panel previously stated it would rely on the most recent October 2022 data to estimate the cost of equity for FEI and FBC. For the Multi-Stage DCF model, Mr. Coyne presents two sets of October 2022 results: 30-trading days versus 90-trading days. FortisBC submits that using 90-day data may still be skewing the DCF results downwards. Both experts agreed that it is reasonable to use longer periods to moderate daily volatility in stock prices and dividend yields. Accordingly, the Panel considers that, under normal market conditions, using 90-day trading data would be both reasonable and preferable to using 30-day trading data.

However, due to the behavior of utility stocks, which went from amongst the best performing to the worst performing segment of the market at about the same time as the latest October 2022 Update, using a 90-trading-day period, which is equivalent to just over four calendar months, risks skewing the October 2022 Multi-Stage DCF results downwards because it would capture the still elevated utility stock prices from July and August 2022 before they became amongst the worst performing around September/October 2022.

Therefore, considering the extraordinary market conditions of 2022, the Panel is willing to accept the use of a shorter 30-trading-day period for utility stock prices and dividend yields. The Panel is further comforted by Dr. Lesser's acknowledgment that he too may use shorter periods depending on "what's happened in the market," though not shorter than 30 days, an approach he did use in 2002 in circumstances that were described as not dissimilar to today's.

Regarding multi-stage DCF models, there are typically two types of such models: a two-stage and a three-stage DCF model. Mr. Coyne only presents the results of a three-stage multi-stage DCF model, with the first two stages lasting five years each and the third stage being the perpetuity stage. Dr. Lesser appears supportive of this approach when he agreed with Mr. Coyne that "the most typical approach is to assume an initial stage lasting five years" and noted that "Mr. Coyne's three-stage model is certainly one approach that is sometimes used, and a five-year middle stage is not unreasonable."

Due to the structure of the model, a three-stage multi-stage DCF model will yield directionally higher ROE results than a two-stage DCF model because the EPS growth rates are only constrained to equal the lower GDP growth rates in Year 11 as opposed to in Year 6. Recognizing that no interveners commented on the pros and cons of using a two-stage versus a three-stage DCF model and that a majority of them supported the three-stage DCF model presented by Mr. Coyne, the Panel finds it reasonable to use a three-stage DCF model to estimate the ROE for FEI and FBC, with the first two stages lasting five years each.

Next, the Panel must evaluate the reasonableness of the data sources for the dividend growth rates in the first and third stage, where the experts disagree. In the first stage, the Panel considers the use of earnings to be reasonable given that dividends are paid out of earnings. The Panel notes that both experts agree that analysts' estimates are the appropriate source for forecast earnings growth rates but disagree on how many data sources to use for the first stage. Recognizing that these are only analysts' estimates, the Panel finds that using multiple sources for these forecasts is better than using a single source because averaging can mitigate the impact of any one forecast that differs from the others. In any case, a sensitivity analysis performed on the December 2021

data shows that using one or four data sources has less than a 10-bps impact on the Multi-Stage DCF model results.

In the third stage, the Panel finds that using the GDP price deflator would be better than using CPI to derive nominal GDP growth rates because CPI only measures inflation related to a subset of all the goods and services produced in the economy, therefore the GDP price deflator is more representative of the market as a whole. However, the Panel accepts that forecasts of the GDP price deflator are not readily available, whereas forecasts of CPI are readily available. Reluctantly, the Panel accepts the use of CPI as a reasonable forecast to be used in the determination of long-term growth rates. The Panel points out that the use of CPI may result in an ROE that is overestimated, but the Panel accepts Dr. Lesser's submission that this difference will not be determinative in the calculation of the overall ROE.

As for the second (transition) stage, the Panel accepts the methodology employed by Mr. Coyne to transition between the first stage and the third stage growth rates.

Based on the above determinations, the Panel finds that Mr. Coyne's choice of inputs for his Multi-Stage DCF model are reasonable to estimate the cost of equity for FEI and FBC. Specifically, the Panel will rely on the October 2022 results using the 30-day average stock prices, modified to exclude the 50-bps adder for flotation costs and financial flexibility, as shown below:

Table 28: Mr. Coyne's Multi-Stage DCF Model results – October 2022 (30-days)[581]

	Canadian Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 30 trading days[582]	10.43%	8.74%	9.53%	8.60%	9.02%

As discussed in Section 3.2 above, the Panel previously determined that the appropriate proxy groups to use for FEI and FBC are the North American gas and electric proxy groups, albeit revised in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which are unlikely to have passed Mr. Coyne's screening criteria if applied strictly.

Table 29 below shows the detail of Mr. Coyne's North American gas proxy groups. Removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group yields a revised calculated average ROE of 8.93 percent,[583] excluding an adder for flotation costs and financial flexibility.

[581] Information in the table is compiled from the referenced footnotes within the table.

[582] Exhibit B1-50, Table 2, Scenario A.3, p. 3.

[583] Calculated by the BCUC using the Average function in Excel = Average (9.67%,8.71%,8.99%,8.12%,9.15%) = 8.93%.

Table 29: 30-Day Multi-Stage DCF - North America Gas Utilities[584]

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
AltaGas Inc.	ALA	$1.06	$26.30	8.63%	7.83%	7.03%	6.23%	5.43%	4.64%	3.84%	9.67%
Canadian Utilities Limited	CU	$1.78	$36.30	4.96%	4.77%	4.58%	4.40%	4.21%	4.02%	3.84%	9.52%
Enbridge Inc.	ENB	$3.44	$51.97	7.08%	6.54%	6.00%	5.46%	4.92%	4.38%	3.84%	12.57%
New Jersey Resources Corporation	NJR	$1.56	$41.51	5.96%	5.66%	5.36%	5.05%	4.75%	4.45%	4.14%	8.71%
Northwest Natural Gas Company	NWN	$1.94	$45.67	4.95%	4.82%	4.68%	4.55%	4.41%	4.28%	4.14%	8.99%
ONE Gas, Inc.	OGS	$2.48	$74.01	5.63%	5.38%	5.13%	4.88%	4.64%	4.39%	4.14%	8.12%
Spire, Inc.	SR	$2.74	$65.69	5.77%	5.50%	5.23%	4.95%	4.68%	4.41%	4.14%	9.15%
MEAN				6.14%	5.78%	5.43%	5.07%	4.72%	4.37%	4.01%	9.53%
Flotation Costs [11]											0.50%
											10.03%

Table 30 below shows the detail of Mr. Coyne's North American electric proxy groups. Removing Canadian Utilities Limited from the North American electric proxy group yields a revised calculated average ROE of 8.99 percent,[585] excluding an adder for flotation costs and financial flexibility.

Table 30: 30-Day Multi-Stage DCF - North American Electric Utilities[586]

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] ROE
Algonquin Power and Utilities	AQN	$0.72	$11.13	8.69%	7.88%	7.07%	6.26%	5.45%	4.64%	3.84%	13.19%
Canadian Utilities Limited	CU	$1.78	$36.30	4.96%	4.77%	4.58%	4.40%	4.21%	4.02%	3.84%	9.52%
Emera Inc.	EMA	$2.76	$54.78	6.05%	5.68%	5.31%	4.94%	4.57%	4.21%	3.84%	10.09%
Hydro One, Ltd.	H	$1.12	$33.26	4.23%	4.16%	4.10%	4.03%	3.97%	3.90%	3.84%	7.54%
Alliant Energy Corporation	LNT	$1.71	$52.89	5.93%	5.63%	5.34%	5.04%	4.74%	4.44%	4.14%	8.06%
American Electric Power Company, Inc.	AEP	$3.12	$88.61	6.30%	5.94%	5.58%	5.22%	4.86%	4.50%	4.14%	8.51%
Duke Energy Corporation	DUK	$4.02	$93.46	5.53%	5.30%	5.07%	4.83%	4.60%	4.37%	4.14%	9.23%
Entergy Corporation	ETR	$4.04	$104.62	5.78%	5.51%	5.23%	4.96%	4.69%	4.41%	4.14%	8.78%
Exelon Corporation	EXC	$1.35	$38.40	7.70%	7.11%	6.52%	5.92%	5.33%	4.74%	4.14%	8.90%
Evergy Inc	EVRG	$2.29	$60.14	5.67%	5.41%	5.16%	4.90%	4.65%	4.40%	4.14%	8.68%
NextEra Energy Inc.	NEE	$1.70	$77.73	9.73%	8.80%	7.87%	6.94%	6.01%	5.07%	4.14%	7.51%
OGE Energy Corporation	OGE	$1.66	$36.59	3.35%	3.48%	3.61%	3.75%	3.88%	4.01%	4.14%	8.82%
Pinnacle West Capital Corporation	PNW	$3.46	$65.75	2.20%	2.52%	2.85%	3.17%	3.49%	3.82%	4.14%	9.22%
Portland General Electric Company	POR	$1.81	$45.06	3.38%	3.51%	3.63%	3.76%	3.89%	4.01%	4.14%	8.28%
MEAN				5.68%	5.41%	5.14%	4.87%	4.60%	4.32%	4.05%	9.02%
Flotation Costs [11]											0.50%
											9.52%

Therefore, the Panel will use a multi-stage DCF ROE, exclusive of an adder for flotation costs and financial flexibility, of 8.93 percent for FEI and 8.99 percent for FBC as it weights the results of the different ROE models.

5.4 Risk Premium Model

The Risk Premium Model is based on the premise that, from an investor's perspective, common equity capital is riskier than debt, because debt has a senior claim over a firm's assets. Consequently, equity investors require a greater return (i.e. an equity risk premium or ERP) than would bondholders. Thus, the Risk Premium model estimates the cost of equity as the sum of the ERP and the yield on a particular class of bonds and can be represented by Equation (6):[587]

$$ROE = ERP + Y \qquad (6)$$

Where:

ROE = return on equity

Y = applicable bond yield

ERP = the equity risk premium (*i.e.*, difference between allowed ROE and the 30-year Treasury Yield)

Dr. Lesser notes that although the Risk Premium Model is similar to the CAPM, it is a distinct methodology. Whereas the CAPM addresses systematic (i.e. non-diversifiable) market risk, the Risk Premium Model directly

[584] Exhibit B1-50, Attachment A.3 FEI – Gas (Oct 2022 update 30 day), Tab JMC-FEI-3 Multi-Stage DCF.

[585] Calculated by the BCUC by averaging the following figures: 13.19%, 10.09%, 7.54%, 8.06%, 8.51%, 9.23%, 8.78%, 8.90%, 8.68%, 7.51%, 8.82%, 9.22% and 8.28%.

[586] Exhibit B1-50, Attachment A.3 FBC – Electric (Oct 2022 update 30 day), Tab JMC-FBC-5 Multi-Stage DCF.

[587] Exhibit B1-8-1, Appendix C, pp. 62–63, Exhibit A2-3, p. 60.

incorporates both systematic and unsystematic (diversifiable) risk. Also, the ERP in this model is not the same as the MRP in the CAPM, which is calculated as the difference between the expected future market return and the risk-free rate. Rather than adding a premium on top of the risk-free rate, the Risk Premium Model adds an ERP to the rate on long-term bonds, where the ERP represents the additional expected return by equity investors to compensate them for the additional risk they face relative to bondholders.[588]

Dr. Lesser notes two implementation issues in the application of the Risk Premium Model to a regulated utility:

1. How is the ERP estimated? In Dr. Lesser's view, this is the most crucial implementation issue because the ERP cannot be observed directly. Like the MRP in the CAPM, the ERP can be based on the historical difference between ROEs and bond yields or based on a forward-looking estimate; and
2. What is the appropriate bond yield to use (Current versus forecast? Same yield as for bonds with the same rating as the regulated utility under review?). As discussed in Section 5.2.1, Dr. Lesser is of the view that investor expectations are fully reflected in the current bond yields, under the Efficient Market Hypothesis.[589]

5.4.1 How is the Equity Risk Premium Estimated?

To estimate the relationship between the ERP and interest rates, Mr. Coyne first conducts a regression analysis using Equation (7) below to estimate the intercept and slope terms and relies on historical authorized returns from a large sample of US gas and electric distribution companies,[590] an approach similar to FERC's.[591] Mr. Coyne also explains that the regression analysis is performed on US data only since there aren't enough Canadian ROE decisions to develop a statistically meaningful regression analysis.

$$ERP = a + (b \times Y) \qquad (7)$$

Where:
ERP = the equity risk premium (*i.e.*, difference between allowed ROE and the 30-year Treasury Yield)
Y = 30-year Treasury Yield
a = intercept term
b = slope term

The regression results, based on the October 2022 data, are shown in Figure 3 and Figure 4 for US gas and electric distribution companies.[592] The relationship between the ERP and the 30-Year Treasury Yields can therefore be written as follows:

U.S. Gas: $ERP = 0.0851 - 0.5775 \times Y$
U.S. Electric: $ERP = 0.0843 - 0.5432 \times Y$

[588] Exhibit A2-3, p. 60.
[589] Ibid., pp. 61–62.
[590] 700 gas utility company rate cases and 859 electric utility company rate cases in the U.S. from 1992 to 2022.
[591] Exhibit B1-8-1, Appendix C, pp. 63–64.
[592] Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".

Figure **3**: Risk Premium Results - U.S. Gas[593]

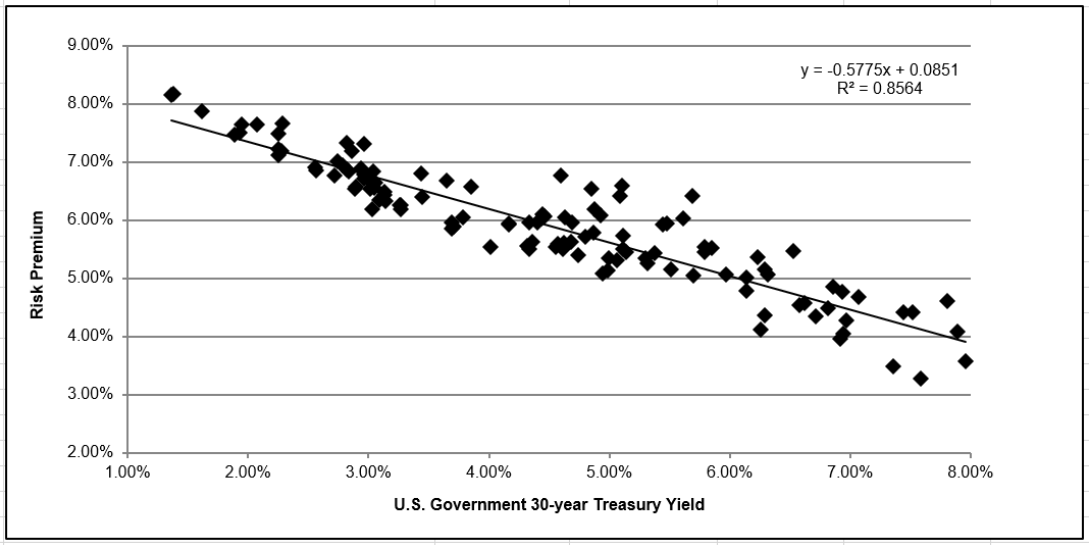
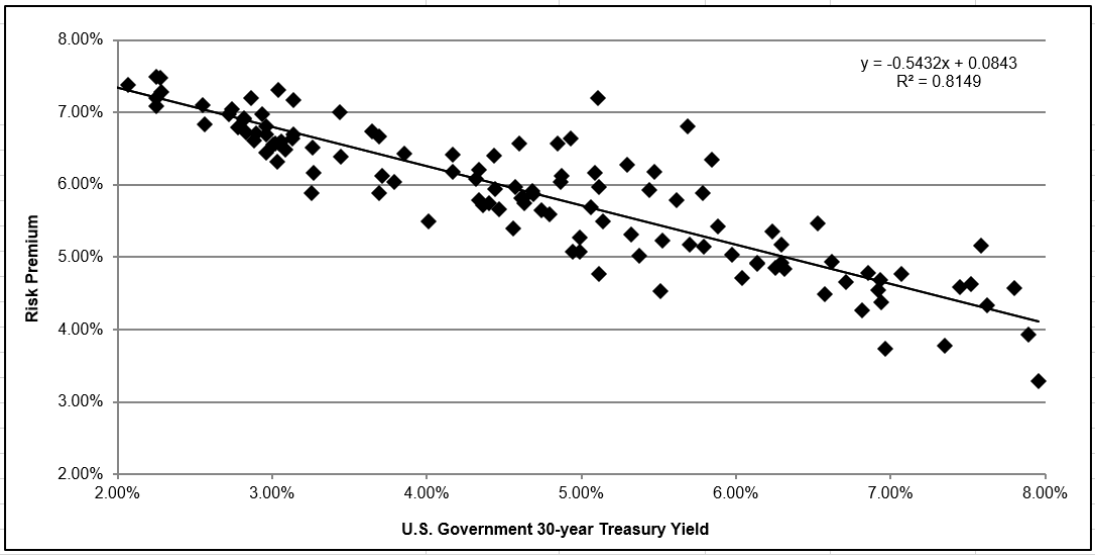


Figure **4**: Risk Premium Results - U.S. Electric[594]



At the oral hearing, Mr. Coyne explained the significance of the high correlation between ERP and bond yields as shown by the high R2 values of 0.86 and 0.82 for gas and electric utilities respectively:[595]

> So what this is trying to get at is how did utility commissions interpret everything that they looked at in these 1500 some odd cases and make a decision regarding allowed return in the investment environment they were in characterized by the bond yield in that period of time? And you can see the -- that's a very strong linear relationship as you can see the trendline.
>
> […] And I'm estimating that relationship because what I want to do is ask myself, given today's bond yields or projected bond yields, and everything we know about these 1500 decisions, what

[593] Exhibit B1-8-1, Appendix C, p. 65. Based on Mr. Coyne's Excel spreadsheet, Mr. Coyne seems to have averaged ROEs by quarter from Q1 1992 to Q4 2021 or Q42021. Thus, there are not 700 or 859 data points in Figure 1 or Figure 2, respectively.

[594] Exhibit B1-8-1, Appendix C, p. 65.

[595] Transcript Volume 4, p. 654, Lines 18–26 to p. 655, Lines 1–16.

would a regulator say about the allowed return, with no other information available to them but just based on bond yields. And it says that […] you can explain 86 or 82 percent of those decision just based by on knowing that bond yield in that period of time. It's a pretty strong association.

5.4.2 What is the Appropriate Bond Yield to Use?

Having estimated the parameters *a* and *b* in Equation (7) from historical data, the second step is to apply the regression's results (*a* and *b*) to long-term bond yields (Y) to estimate the ERP in Table 31 from Equation (7). To do so, Mr. Coyne uses both the current (30-day average) and forecast bond yields of the 30-year Treasury Yield. For the forecast bond yields, Mr. Coyne uses a near-term and a five-year forecast (see Table 31). In Mr. Coyne's view, the five-year forecast is the most applicable because investors are expecting increases in government bond yields and investors typically have a multi-year view of their required returns on equity.[596] For instance, the ERP of 6.32 percent for the US gas proxy group in the 4th column is estimated as follows:

U.S. Gas: $ERP = 0.0851 - 0.5775 \times Y$

$ERP = 0.0851 - 0.5775 \times Y$
$ERP = 0.0851 - 0.5775 \times 0.038$

$ERP = 0.0632 \; or \; 6.32\%$

Then, the resulting ROE is computed using Equation (6):

$ROE = ERP + Y$
$ROE = 6.32\% + 3.80\% = 10.12\%$

Table 31: Risk Premium Results for FEI and FBC – October 2022[597]

	U.S. Gas Proxy Group			U.S. Electric Proxy Group		
	30-Day average yield on 30-year treasury bond	Q2 2023-Q2 2024 forecast for yield on 30-year treasury bond	**2024-2028 forecast for yield on 30-year treasury bond**	30-Day average yield on 30-year treasury bond	Q2 2023-Q2 2024 forecast for yield on 30-year treasury bond	**2024-2028 forecast for yield on 30-year treasury bond**
Yield	3.92%	4.00%	**3.80%**	3.92%	4.00%	**3.80%**
ERP	6.25%	6.20%	**6.32%**	6.30%	6.26%	**6.36%**
Resulting ROE[598]	10.17%	10.20%	**10.12%**	10.22%	10.26%	**10.16%**

5.4.3 Overall Risk Premium Model Results

While the Risk Premium Model is simple and easily replicable, Dr. Lesser points to a commonly cited weakness of the model: circularity, due to its reliance on prior regulatory decisions. He also highlights other potential flaws in

[596] Exhibit B1-8-1, Appendix C, pp. 65–67.
[597] Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".
[598] Exhibit B1-50, p. 6: per Footnotes 3 and 4, the risk premium results do not include 50 bps for flotation costs and financial flexibility.

its implementation. For instance, the regression specification (with only one explanatory variable) assumes that no other factors can influence investors' expected return requirements (e.g. business risk, financial risk, capital structure, degree of regulated versus unregulated activities). So, unless this is true, the model specification suffers from "omitted variable bias" and the slope coefficient "*b*" is likely to be biased. Additionally, Dr. Lesser states that this approach fails to consider differences in risk associated with those previously established allowed returns, such that it will not capture the fundamental relationship between risk and return. Thus, the resulting ERP value may not reflect a risk-comparable ROE and thus may not meet the Fair Return Standard. Another problem is to select a historical period where the relationship between the ERP and bond yields is constant and representative of current capital market conditions.[599]

In summary, Dr. Lesser cautions regulators when using a regression model to calculate the relationship between historical ERPs and bond yields, as they must evaluate the model itself, the time period selected, and the validity of the implicit assumptions that the estimated relationship will be valid on a going-forward basis. In Dr. Lesser's view, simple linear models relating ERPs to bond yields are fraught with empirical estimation issues that can lead to biased parameter values.[600] Additionally, Dr Lesser states that models that use historical allowed returns to estimate ERP values suffer from unavoidable circularity.[601] Dr. Lesser also states that, based on his experience over the last 20 years, he does not recommend use of the Risk Premium methodology.[602]

In response to these critiques, Mr. Coyne remarks that, after hearing these and other arguments in the context of setting ROEs for electric transmission companies, FERC ultimately concluded:[603]

> The Risk Premium model has a strong theoretical basis. We continue to find that the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models. […] While the Commission in Opinion No. 569 noted its concerns with the Risk Premium model as proposed by the Briefing Order, the Commission found in Opinion No. 569-A that these concerns are mitigated by modifications that the Commission made to the Risk Premium model as well as the fact that the Commission will average the results of the Risk Premium with the DCF and CAPM. We reaffirm this finding here.

Mr. Coyne states that he agrees with FERC that the benefits of the Risk Premium Model outweigh its weaknesses and the model provides a stabilizing influence when averaged with the CAPM and DCF model, which can be especially attractive in the presence of volatile market and economic conditions.[604] At the oral hearing, Mr. Coyne explained that he likes to use multiple models, including the risk premium, as "they give you a little bit more resilience from the pure market-based models, the DCF and the CAPM, that tend to get whip-sawed by [fluid and dynamic market] circumstances". [605]

This stabilizing influence and resilience can be seen in the table below, which presents Mr. Coyne's ROEs from the Risk Premium Model at different points in time throughout the proceeding. Those results reflect Mr. Coyne's

[599] Exhibit A-3, pp. 65–66.
[600] Exhibit A-3, p. 67.
[601] Exhibit A2-3, p. 67.
[602] Exhibit A2-8, Dr. Lesser Response to FortisBC IR 17.1.
[603] Exhibit B1-8-1, Appendix C, p. 63.
[604] Ibid.
[605] Transcript Volume 3, p. 171, Lines 16–26 to p. 172, Lines 1–9.

preferred approach of using the five-year forecast bond yield as the basis to compute the ROE. For clarity, these results do not include an adder for financial flexibility and flotation costs.

Table 32: Mr. Coyne's Risk Premium Model's ROE Results[606]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
December 2021[607]	n.a.	9.97%	9.97%	10.01%	10.01%
September 2022[608]	n.a.	10.12%	10.12%	10.17%	10.17%
October 2022[609]	n.a.	10.12%	10.12%	10.16%	10.16%

FortisBC submits that the Risk Premium Model produces results that are supportive of Mr. Coyne's recommendations and merits the BCUC's consideration due to its theoretical validity and stability. FortisBC states that Dr. Lesser accurately characterizes the Risk Premium Model as "in effect, a simpler version of the CAPM", simpler because it focuses on bond yields as one driver of the cost of capital. While the Risk Premium Model is simpler, FortisBC notes that FERC recognizes its theoretical validity and value, as it has adopted the Risk Premium Model as one of its three methods (which it weights equally) for determining the cost of capital for regulated electric transmission companies.[610]

FortisBC notes that Mr. Coyne's Risk Premium Model involved examining the allowed ROEs from a large sample of US gas and electric distribution companies from 1992 to 2021 to determine the existence of a high correlation between allowed ROEs and government bond yields. Mr. Coyne then applies the regression results to current and forecast bond yields, with the latter resulting in a ROE of 10.12 percent and 10.16 percent for the US gas and electric proxy groups, respectively, based on October 2022 data. FortisBC notes that the results based on *current* bond yields (Dr. Lesser's preference) would be slightly higher because forecast government bond yields are lower than current government bond yields in October 2022.[611]

FortisBC concludes that the Risk Premium Model results are consistent with Mr. Coyne's recommended ROEs for FEI and FBC, both in terms of direction and magnitude. FortisBC stresses that these results are based on US utilities that have, on average, much thicker common equity ratios than FEI and FBC. Other things being equal, FortisBC submits that one would expect the ROE values to be higher when applied to a utility with thinner equity.[612]

[606] Information in the table is compiled from the referenced footnotes within the table.
[607] Exhibit B1-8-1, Appendix C, Figures 1, p. 4 and Figure 2, p. 5.
[608] Exhibit B1-8-1-2, Figure 1, p. 2 and Figure 3, p. 3.
[609] Exhibit B1-50, Figures 3 and 4, p. 6.
[610] FortisBC Final Argument, p. 138.
[611] Ibid., pp. 138–139.
[612] Ibid., p. 139.

Positions of Parties

The CEC

The CEC notes that the Risk Premium Model is simpler to understand and its use as a check for reasonableness of results is appropriate.[613]

RCIA

RCIA is the only intervener that made detailed final submissions in relation to the Risk Premium Model. In RCIA's view, this model is simple and provides accurate and reliable estimations of ROE, as well as an intuitive framework to understand other FortisBC ROEs and how the selection of assumptions impact ROE estimates.[614] RCIA submits that, even though Mr. Coyne's ROE recommendations are only based on the CAPM and Multi-Stage DCF and that Mr. Coyne's Risk Premium Model is not directly applicable to Canadian utilities, important insights can be gained from the Risk Premium Model, namely that:

1) Approved ROEs can be modelled using a simple regression analysis, using the bond yield as the independent variable; and
2) A statistically significant multi-year linear relationship exists between interest rates (bond yields) and risk premiums derived from US utilities' approved ROEs.[615]

RCIA notes that, while the model shows an inverse correlation between bond yields and risk premiums, as bond yields rise, the risk premium decreases, but by less than the nominal value of the bond yield increase. As shown in the regression results of Figure 3 and Figure 4, when bond yields increase by 100 bps, the risk premium decreases by 58.32 bps and 55.08 bps for US gas and electric utilities, respectively.[616] Thus, as shown in Table 31 above, RCIA notes that higher interest rate assumptions result in higher ROEs. RCIA submits that, in Table 31, "the interest rates were boosted by the forecast to be 0.65% and 1.53% higher, resulting in 0.27% and 0.64% higher ROE for U.S. Gas estimate and 0.29% and 0.69% higher ROE for U.S. Electric estimate."[617]

In RCIA's view, the problem with inclusion of forecast data is that the implied results are only appropriate if the actual data (i.e. bond yield) equal the forecast. RCIA notes that the inclusion of forecast values is also a point of disagreement between Mr. Coyne and Dr. Lesser, the latter of whom states that actual market prices inherently reflect expectations while forecasts are unreliable. RCIA is also concerned with using the average of multiple years and time periods to generate the (forecast) bond yield assumption. In RCIA's view, this approach introduces randomness and error akin to Dr. Lesser's dartboard analogy ("If markets are not efficient, then no methodology is accurate. You might as well throw darts at a dartboard.")[618]

RCIA submits that Mr. Coyne applies judgement to bolster the results derived from the modelling to benefit his client. In RCIA's submission, the recommended ROE is higher than would be the case had actual bond yields

[613] The CEC Final Argument, p. 40.
[614] RCIA Final Argument, p. 4.
[615] RCIA Final Argument, pp. 5–6.
[616] Ibid., p. 6.
[617] Ibid., p. 8.
[618] Ibid., p. 9.

(which is the basis of the construction of the regression analysis) been used. The result is a bias that produces a higher than required result. At a minimum, RCIA submits that to be considered, the Risk Premium Model should be based on non-biased assumptions and results.[619]

FortisBC Reply Argument

FortisBC remarks that RCIA favours using the Risk Premium Model as a primary model and characterizes it as "simple and provid[ing] accurate and reliable estimations of ROE". FortisBC has two points in response to RCIA's submissions:[620]

1) RCIA's proposed ROEs are far below what the Risk Premium Model suggests; and
2) The Risk Premium Model output reinforces the CAPM and Multi-Stage DCF results.

On the first point, FortisBC states that it is impossible to reconcile RCIA's endorsement of the Risk Premium Model with the ROE values that RCIA is advocating. RCIA's proposed ROE values of between 8.0 percent and 8.75 percent are far below the Risk Premium Model output based on October 2022 *forecast* bond yields (10.12 percent and 10.16 percent for US gas and electric proxy groups, respectively) and *actual* bond yields (10.17 percent and 10.22 percent for US gas and electric proxy groups, respectively[621]). The results based on actual bond yields (RCIA's preference) are higher in October 2022 because forecast government bond yields were lower than actual government bond yields. FortisBC reiterates that the October 2022 outputs are relatively constant with Mr. Coyne's recommended ROEs for FEI and FBC, both in terms of direction and magnitude.[622]

On the second point, FortisBC notes that RCIA argues that the Risk Premium Model reveals a potential weakness in Mr. Coyne's other models. Specifically, RCIA observes that the Risk Premium Model suggests that the ROE should increase as interest rates increase, and notes that Mr. Coyne's CAPM and DCF results have decreased slightly in September 2022 relative to December 2021 despite increasing interest rates.[623] FortisBC agrees and emphasizes that Mr. Coyne explains the transitory nature of the September 2022 results and that the October 2022 results have increased markedly and shift back to approximate those from December 2021. FortisBC submits that "RCIA's notion that the transitory results in September 2022 calls the model itself into question is predicated on the fallacy that all models should produce the same results at all times".[624] The reason why Mr. Coyne and Dr. Lesser both favour the use of multiple models is because the models have their own strengths and weaknesses and respond differently in different conditions. Mr. Coyne considers various models to check the reasonableness of his model and any model may, at specific times and due to events such as market disruptions, result in estimates that would require adjustments or judgement. FortisBC notes that Dr. Lesser's practice is no different.[625]

[619] RCIA Final Argument, p. 10.
[620] FortisBC Reply Argument, pp. 73–74.
[621] Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".
[622] FortisBC Reply Argument, p. 73.
[623] Ibid.
[624] Ibid., p. 74.
[625] Ibid., pp. 73–74.

Panel Determination

The Panel considers that using multiple models recognizes that each of the models has its own strengths and weaknesses and responds differently in different conditions. Relying on more models is especially important at times when the pure market-based models like the DCF and CAPM tend to get whipsawed by volatility in the market. As a case in point, the Risk Premium Model yields ROE results that remain within a very narrow range of about 15 bps throughout the proceeding, whereas up and down movements in the CAPM and multi-stage DCF models have been a lot more pronounced at times.

Therefore, the Panel finds that considerable weight should be given to the use of a Risk Premium Model for the purposes of determining the appropriate ROE for FEI and FBC given the volatility in the market and economic conditions. The specific weight to be accorded the Risk Premium Model in the respective ROEs will be discussed in Section 6.3 (Overall Capital Structure and ROE).

The strengths of the Risk Premium Model outweigh its shortcomings. The Panel finds that a strength of the Risk Premium Model is its theoretical validity and stability. We also find that this model is easy to understand. A weakness of the Risk Premium Model is the circularity of the model, due to its reliance on prior regulatory decisions. However, the Risk Premium Model is not the only model that can be prone to similar circularity risks. For instance, in the DCF model, prior regulatory decisions on the proxy companies' authorized ROEs are likely to influence the inputs to the model such as utility stock prices. Consequently, the Panel considers that circularity concerns alone do not justify eliminating reliance on the Risk Premium Model, or any particular model, for determining the appropriate ROE for FEI and FBC. Instead, it is a factor in the overall consideration of model results.

Mr. Coyne states that he agrees with FERC that the benefits of the Risk Premium Model outweigh its weaknesses and the Risk Premium Model provides a stabilizing influence when averaged with the CAPM and DCF model, which can be especially attractive in the presence of volatile market and economic conditions. Although FERC's determinations are not binding on the BCUC, the Panel notes that FERC has recognized the theoretical validity and value of the Risk Premium Model, as it has adopted that model along with the CAPM and DCF model, which it weights equally for determining the cost of capital for regulated electric transmission companies in the US.

Having determined to give weight to the Risk Premium Model, the Panel must now decide what is the appropriate bond yield to use, whether current or forecast. To be consistent with its previous determination on the risk-free rate used in the CAPM (see Section 5.2.1), the Panel will also rely on the forecast for the yield on 30-year treasury bond, specifically the results using the five-year forecast:

Table 33: Mr. Coyne's Risk Premium Results - October 2022[626]

	Canadian Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022[627]	n.a.	10.12%	10.12%	10.16%	10.16%

[626] Information in the table is compiled from the referenced footnotes within the table.
[627] Exhibit B1-50, Figures 3 and 4, p. 6

Mr. Coyne did not adjust the Risk Premium Model ROE results by adding 50 bps to account for flotation costs or financial flexibility. The Panel understands that the Risk Premium Model relies on past regulatory decisions on authorized ROE to calculate the risk premium such that the underlying data points used in the equation are already inclusive of any adder regulators would have deemed appropriate.

Since there are not enough Canadian ROE decisions, Mr. Coyne has performed the regression analysis on US data only, and therefore, the Risk Premium Model results are applicable to US utilities. In the revised North American proxy groups from which Enbridge Inc. and Canadian Utilities Limited are removed, a majority of the proxy companies are from the US. As a result, the Panel finds that the Risk Premium Model ROE results are applicable to the revised North American proxy groups. Therefore, the Panel will use a Risk Premium Model ROE of 10.12 percent for FEI and 10.16 percent for FBC as it weights the different ROE models.

6.0 OVERALL PANEL DETERMINATION ON CAPITAL STRUCTURE AND ROE

Section 4 previously discussed the evidence and interveners' respective submissions on credit ratings and business risks as they relate to capital structure. In Section 5, the Panel reviews the various financial models used to calculate the ROE. In Section 6.1 below, the Panel considers FortisBC's and the interveners' recommended ROE, based largely on the results of these financial models before any flotation costs and financial flexibility adder and other adjustments. Section 6.2 focuses on the topic of flotation costs and financial flexibility. Finally, Section 6.3 considers FortisBC, the two experts (Mr. Coyne and Dr. Lesser), and the interveners' recommended capital structure and overall ROE, inclusive of all adders and other adjustments. Parties presented a range of reasonable possibilities in both the deemed equity component and allowed ROE in Stage 1. In the overall determination section, we give appropriate weight that reflects our findings above and make final determinations on the deemed equity component and allowed ROE for FEI and FBC, respectively.

6.1 ROE Before Adders and Other Considerations

FortisBC submits that the evidence in this proceeding supports a finding that the required cost of equity for FEI and FBC is, respectively, 10.1 percent (on 45 percent common equity) and 10.0 percent (on 40 percent common equity).[628] These figures are based on the US proxy groups and December 2021 data and consist of a simple average of Mr. Coyne's CAPM and Multi-Stage DCF model results. They are also inclusive of a 50-bps adder for flotation costs and financial flexibility.[629] FortisBC states that these proposed ROEs are based on the recommendations of Mr. Coyne, who is the only expert in this proceeding who conducted a full cost of capital analysis.[630]

In its final argument, FortisBC notes the experts' alignment on key aspects of the ROE analysis, including the use of multiple models, using Mr. Coyne's proxy groups with more reliance on North American proxy groups, and the reasonableness of relying primarily on the most recent October 2022 data.[631] FortisBC states that Mr. Coyne's model results based on October 2022 data align with current economic and market conditions[632] and

[628] FortisBC Final Argument, p. 121.
[629] Exhibit B1-8-1, Appendix C, Figure 1, p. 4, Figure 2, p. 5.
[630] FortisBC Final Argument, p. 121.
[631] Ibid., para. 244(b), p. 121.
[632] Ibid., para. 249, p. 124.

notes that there is a reasonable alignment between results based on the October 2022 data and the December 2021 data.[633]

BCOAPO points out that Mr. Coyne's original evidence, based on the December 2021 data, recommends ROEs for FEI and FBC of 10.1 percent and 10.0 percent, respectively but the updated information Mr. Coyne provided using October 2022 data results in ROEs of 9.5 percent and 9.63 percent for FEI and FBC, respectively[634]. Despite this, BCOAPO notes that FortisBC's position in its final argument remains the same as it was prior to the oral hearing. BCOAPO questions why FortisBC still pursues the higher ROEs in the face of more current data. BCOAPO submits that the evidence is clear that FortisBC's position is not based on the best evidence available and as such, FortisBC's applied-for ROE levels should not be approved.[635]

As this section focuses on the ROE before any adders for flotation costs, financial flexibility, or other considerations, subtracting 50 bps from the aforementioned FortisBC's requested ROEs yields ROEs of 9.51 percent for FEI and 9.50 percent for FBC, respectively.

Like FortisBC, the interveners have based their respective ROE recommendations on either a simple average of their CAPM and Multi-Stage DCF model ROEs (ICG, BCOAPO and the CEC) or on the CAPM ROE, only (RCIA), but have not incorporated the ROE derived from the Risk Premium Model into their ROE recommendations. Reflecting our cumulative determinations on the various inputs to the CAPM (such as a preference to use forecast bond yields to estimate the risk-free rate and a constant DCF model to estimate the forward-looking MRP, as well as giving equal weight to the historical and forward-looking MRP, and not including a Hamada adjustment or a size premium), we do not propose to further review the CAPM ROE recommendations made by ICG, BCOAPO and RCIA because they all favour different inputs into the CAPM. Similarly, our earlier acceptance of a 30-trading-day period to calculate utility stock prices and dividend yields in the Multi-Stage DCF model also means that we will not consider the Multi-Stage DCF ROE recommendations made by BCOAPO and the CEC that favour a 90-trading-day average. Consequently, we do not propose to review in detail the interveners' ROE recommendations before any flotation costs and financial flexibility adder and other adjustments.

6.2 Flotation Cost and Financial Flexibility

6.2.1 Flotation Cost

Flotation costs are associated with issuing new equity, which include legal fees, out-of-pocket expenditures for the preparation, filing, underwriting, and other costs associated with the issuance of common equity.[636] Both Mr. Coyne and Dr. Lesser note that regulators often include an allowance for flotation costs.[637] However, the experts have a difference in opinion on how flotation costs should be recovered and the size of the adjustment for flotation costs.

[633] FortisBC Final Argument, para. 295, p. 146.
[634] These figures are based on 90-day average stock prices and interest rates.
[635] BCOAPO Final Argument, p. 54.
[636] Exhibit A2-3, p. 82, Exhibit B1-8-1, Appendix C, p. 69.
[637] Ibid., Executive Summary, p. 2, Exhibit B1-8-1, Appendix C, p. 69.

Recovery Mechanism

Mr. Coyne submits that because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires.[638] Mr. Coyne explains that if FEI and FBC were standalone utilities and issued their own equities, the associated flotation costs could have been recovered in cost of service. In the absence of this possibility given the utilities are not publicly traded, the addition of flotation cost to the ROE is the only feasible approach.[639]

Furthermore, Mr. Coyne explains that flotation costs are part of the invested costs of the utility, which are reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore, are not reflected on the income statement. Like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time, remain part of the cost structure and as such, should be recovered through ROE.[640] The effect of the ROE adder for flotation costs is to treat issuance costs as if they are a rate base item on which FEI and FBC earn a return that flows back to Fortis Inc. as compensation for incurring the costs.[641]

Mr. Coyne submits that flotation cost is compensated each and every year rather than only on the incremental amount of capital as a result of a change in capital structure. Mr. Coyne further explains that the equity is permanent capital, and flotation cost is a charge for having the equity infused into the company.[642] In other words, as Mr. Coyne notes, "unlike debt, equity has an indefinite life and does not mature. Therefore, costs associated with the equity issuance are recovered over the life of the equity."[643]

In contrast, Dr. Lesser states that he favours compensating utilities for the actual flotation costs incurred, and states it may be more reasonable to include actual flotation costs (or an estimate of those costs) as an expense to be recovered in the regulated utility's cost of service.[644] In particular, if the utility is not traded publicly, but is a subsidiary of a publicly traded parent, and the parent company issues new equity to finance investment by the utility subsidiary, then the most equitable way to compensate the utility is by allowing it to recover all of the known and measurable costs of the stock issuance, rather than through an arbitrary increase in allowed ROE that is unlikely to reflect those actual issuance costs.[645] Dr. Lesser elaborates that an adjustment for flotation costs to allowed ROE will compensate the utility based on its rate base, not on the actual flotation costs incurred, and that an arbitrary percentage is likely to overcompensate the utility for flotation costs.[646] Hence, Dr. Lesser points out that "FERC does not grant a flotation cost adjustment to allowed ROE unless the firm under review can demonstrate it issued stock and incurred flotation costs."[647]

[638] Exhibit B1-8-1, Appendix C, p. 69.
[639] Exhibit B1-9, BCUC IR 43.4.
[640] Exhibit B1-21, Part 2, p. 22.
[641] Transcript Volume 3, p. 346.
[642] Ibid., pp. 342–343.
[643] Exhibit B1-13, RCIA IR1 31.3.
[644] Exhibit A2-3, p. 85.
[645] Exhibit A2-20, BCUC IR 6.3.
[646] Exhibit A2-3, p. 85.
[647] Ibid.

Size of an ROE adder for Flotation Cost

Regarding the appropriate size of flotation costs, Mr. Coyne makes adjustments to the DCF and CAPM results by 50 bps for flotation costs and financing flexibility.[648] However, while Mr. Coyne does not provide a breakdown of the 50-bps adjustment separating flotation costs from financing flexibility, Mr. Coyne notes that for an electric proxy group in the US, flotation costs are typically in the range of 10 to 15 bps and the remainder would be for financing flexibility (i.e. 35 to 40 bps).[649]

Dr. Lesser provides his view on issuance costs as a percentage of equity issued and notes that flotation costs typically have ranged between two percent and five percent of issuance costs[650] to which Mr. Coyne assesses, "doesn't sound unreasonable."[651] Using an assumed flotation cost equal to five percent of total issuance cost and Dr. Lesser's methodology to calculate flotation cost, Mr. Coyne converts Dr. Lesser's data into basis points of ROE, indicating that issuance costs of that magnitude represent approximately 21 to 25 bps of ROE for the gas proxy groups and 19 to 25 bps for the electric proxy groups.[652] Mr. Coyne notes that his estimate of 10 to 15 bps and Dr. Lesser's estimates of 25 bps are "within the range of what we would expect to see for issuance costs."[653]

Table 34: Flotation Cost Adder: Dr. Lesser's Methodology

Flotation Cost Adder: Dr. Lesser's Methodology (basis points)

Proxy Group	FEI	FBC
Canadian Regulated	25	25
US Gas	21	
North American Gas	24	
US Electric		19
North American Electric		20

6.2.2 Financial Flexibility

Financial flexibility refers to a margin, or cushion, for unanticipated capital market conditions,[654] or also as spare borrowing capacity[655] and ability to continue to raise equity in challenging capital market conditions.[656]
Dr. Lesser and Mr. Coyne disagree on inclusion of costs for financial flexibility to compensate for raising capital. Also, if financial flexibility is accounted for, there are varying opinions as to whether the financial flexibility adder should form part of the allowed ROE or deemed equity component of the capital structure.

Dr. Lesser

Dr. Lesser notes that in the academic literature, financial flexibility appears to be defined as having spare borrowing capacity and additional cash-on-hand, and thus, appears to be more related to the optimal capital

[648] Exhibit B1-8-1, Appendix C, p. 72.
[649] Exhibit B1-9, BCUC IR 43.2; 50-bps adjustment less flotation costs range of 10-15 bps equals to 35–40 bps for financial flexibility costs as the residual.
[650] Exhibit A2-3, p. 82.
[651] Transcript Volume 4, p. 624, ll. 5-17 and p. 625, ll. 6-23.
[652] Exhibit B1-25, BCUC IR1 6.1.
[653] Transcript Volume 3, p. 354.
[654] Exhibit A2-20, BCUC IR 6.6; 2013 Decision, p. 79.
[655] Exhibit A2-20, BCUC IR 6.6.
[656] Exhibit B1-8-1, Appendix C, p. 69.

structure and less one of the allowed ROE.[657] Therefore, because financial flexibility is related to capital structure, it is Dr. Lesser's opinion that, if the BCUC wishes to increase the allowed returns earned by FEI and FBC to account for financial flexibility, such flexibility is best incorporated into the capital structure the BCUC sets for FEI and FBC by adjusting each utility's deemed equity ratios.[658] He does not consider an adder for financial flexibility to be just and reasonable.[659] Dr. Lesser also explains that given the efficiency of capital markets, it is unclear why a regulated utility requires an allowance above its allowed ROE as a financial cushion to enable it to raise funds "under a variety of economic and market conditions," nor whether this "variety" of conditions is limited solely to financial crises, which are themselves undefined.[660] He questions whether the benefits to ratepayers of this financial cushion exceed the costs.[661]

Mr. Coyne

Mr. Coyne submits that financial flexibility is necessary so that utilities such as FEI and FBC have the ability to raise capital under a variety of economic and market conditions, including periods such as the financial crisis of 2008/2009 and the COVID pandemic of 2020 to 2022.[662]

Additionally, Mr. Coyne submits that the optimal approach would be to establish financial parity with the US peer group, so that from an investor perspective, they are receiving equivalent returns and the utility would have comparable financial strength during all market conditions.[663] Mr. Coyne submits that if a Canadian regulator was looking to establish financial parity with US peers, then establishing comparable equity ratios (in the 50 percent to 52 percent range) and comparable allowed ROEs (9.5 percent to 10.0 percent range) would accomplish that objective,[664] and in doing so, would obviate the need for a "financial flexibility" adder to the ROE, as the Canadian utility would now have financial comparability to its US peers which do not have an equivalent adder.[665]

In response to undertakings to the oral hearing, Mr. Coyne performed a WACC analysis to calculate how the proposed 50-bps flotation cost and financial flexibility ROE adder can be reflected in the capital structure. Mr. Coyne determined that FEI's deemed equity ratio would need to increase by 2.0 percent to 2.3 percent for FEI and by 2.1 percent for FBC to account for recovery of flotation costs and financial flexibility through each utility's deemed capital structure. The results are summarized in the following table:

[657] Exhibit A2-20, BCUC IR 6.6.
[658] Ibid.
[659] Ibid.
[660] Ibid.
[661] Ibid.
[662] Exhibit B1-9, BCUC IR 43.1.
[663] Exhibit B1-51, BCUC IR 1.3.
[664] Ibid., BCUC IR 1.1.
[665] Ibid.

Table 35: Adjustment to Equity Ratio[666]

Adjustment to Equity Ratio for Flotation Costs and Financial Flexibility		
	Equity Ratio	Adjusted for Flotation and Financial Flexibility
FEI – current	38.5%	40.51%
FEI – proposed	45.0%	47.34%
FBC – current/proposed	40.0%	42.10%

As noted above, Mr. Coyne does not provide a breakdown of the 50-bps adjustment separating flotation costs from financing flexibility but Concentric explains that for an electric proxy group in the US, flotation costs are typically in the range of 10 to 15 bps and the remainder would be for financing flexibility (i.e. 35 to 40 bps).[667]

FortisBC

FortisBC submits that an adjustment for financial flexibility is required to compensate FortisBC for the additional margin of equity above approved equity ratio that it must maintain to remain compliant with the ring-fencing provision. FortisBC explains that ring-fencing occurs when a regulated public utility business financially separates itself from a parent company that engages in non-regulated business in order to mitigate possible risks arising from the financial status of the parent companies and non-regulated affiliates. A common concern cited in support of ring-fencing is the potential for a parent company to leverage the utility beyond the allowed equity thickness so as to earn an equity return on what is, in reality, debt financing.[668] Therefore, in order to consistently comply with this condition and to manage market volatilities, FortisBC explains that FEI maintains a cushion in its equity structure since its actual capital structure is not constant and will inevitably fluctuate depending on its financing needs.[669]

FortisBC argues that most Canadian regulators apply a premium to the approved ROE to account for the needed financial flexibility. In contrast, the majority of US regulators do not "deem" the equity thickness and rely upon the utility's actual stand-alone capital structure at the end of the test year.[670] FortisBC further states that the financial flexibility adder to the allowed ROE recognizes this fact and provides some compensation to the equity investor for the added layer of equity it provides above the regulated common equity ratio. In the absence of the financial flexibility adder, FEI would not be compensated for the additional margin of equity above approved equity ratio that it must maintain to remain compliant with this provision.[671]

In the oral hearing, FortisBC explained to the Panel that it tries to be in a position where it is "not slipping below the level of equity in the deemed [capital] structure."[672] FortisBC confirms its strategy to include financial flexibility in order to manage a capitalization that is "conservative and takes into account market disruptions so

[666] Exhibit B1-50, Undertaking No. 2, Attachment U.2.
[667] Exhibit B1-9, BCUC IR 43.2; 50-bps adjustment less flotation costs range of 10–15 bps equals to 35-40bps for financial flexibility costs as the residual.
[668] Exhibit B1-51, BCUC IR 2.1.1.
[669] Exhibit B1-51, BCUC IR 2.1.1.
[670] Exhibit B1-50, Undertaking #2, p. 1.
[671] Exhibit B1-51, BCUC IR 2.1.1.
[672] Transcript Volume 5B, p. 858.

that we [FortisBC] are never in a position where we're [FortisBC] over levered", regardless of whether it has an actual equity thickness of 38.5 percent or 45 percent or a different equity thickness.[673] An excerpt from the Transcript for the oral hearing is provided below:[674]

> COMMISSIONER LOSKI: I have a follow-up question, Mr. Lorimer. That strategy you just described, do you anticipate that would be the same if you have an equity thickness of 38 and a half percent or 45 percent or something else?
>
> MR. LORIMER: A: You know, to me it's a good strategy in either case. You know, I think that, you know, provides that level of comfort that we're not straying too far over and always on the proper side of the allowed return -- or the allowed equity fitness. I think to the extent you got, you know, less and less levered and you got a view from our rating agencies that they were comfortable, I guess, with the amount of leverage that we had. You know, there's probably more of an opportunity that more -- a bit less conservative on how that's done. But, you know, generally, like I'd like to be in a position where I can say that we're not slipping below the level of equity in the deemed structure. And especially for FEI, I guess, where the ring-fencing provisions are in and, you know, the requirements to keep at that level are a little bit more firm. You know, try to make sure that we're always cognizant of those provisions as well.

In addition, FortisBC submits that the existing 50-bps adder is helping to sustain FEI and FBC's existing credit ratings. The removal of the adder could be viewed as credit negative, particularly if the adjustment becomes "lost in broader business and financial risk considerations if evaluated with equity ratios."[675]

Positions of Parties

FortisBC submits that the BCUC should find that issuance costs[676] for FEI and FBC are reasonably estimated as being at least 25 bps.[677] With regards to financing flexibility, FortisBC submits that firstly, it compensates the utility for maintaining a buffer of equity above the deemed equity ratio, which is key to financial integrity. Second, from the perspective of comparable earnings and capital attraction, it addresses the lower overall returns in Canada relative to US companies with which Canadian utilities compete for capital.[678] In addition, FortisBC submits that the "existing 50 bps adder is helping to sustain FEI's and FBC's existing credit ratings."[679]

The CEC, ICG and BCOAPO support FEI's proposed adders for flotation costs and financial flexibility to varying degrees.

The CEC and ICG support a 50-bps adder for flotation costs and financial flexibility.[680]

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[673] Transcript Volume 5B, p. 857.
[674] Ibid., pp. 857– 859.
[675] Exhibit B1-51, BCUC Undertaking IR 1.3.
[676] The terms "floatation costs" and "issuance costs" are used interchangeably.
[677] FEI and FBC Final Argument, p. 184.
[678] Ibid.
[679] FortisBC Final Argument, pp. 191–192.
[680] The CEC Final Argument, p. 57, ICG Final Argument, p. 17. It is noted that the CEC and ICG have double-counted the 50-bps adder, as they both added 50 bps to ROE figures that were already inclusive of a 50-bps adder for flotation costs and financial flexibility.

The CEC submits that the continuation of a 50-bps adder for flotation costs and financial flexibility is warranted and reasonable.[681] In addition, the CEC submits that a company may raise more capital than explicitly needed and carry a buffer amount of equity above its deemed equity ratio thus supporting its financial flexibility and integrity which "also goes some distance to compensate for lower overall returns in Canada relative to US companies."[682] The CEC submits that US utilities do not have an adder for flotation costs and financial flexibility, and that US utilities have in fact been provided considerable flexibility.[683] The CEC suggests that the BCUC may want to enable utilities in BC to have some of the flexibilities US utilities use to avoid the need for an explicit adder. Furthermore, the CEC recommends that in the processes triggered out of this proceeding, it would be useful to ask FEI, as the Benchmark Utility, to recommend to the BCUC flexible processes that US utilities have which could make the cost of capital processes simpler and operational without the need for adders.[684]
BCOAPO does not disagree that issuance costs are valid but, in BCOAPO's submission, there is not sufficient evidence on the record to establish any specific ROE adjustment. "At best, BCOAPO submits that it can confidently opine that it is likely no more than 25 basis points and could be materially less."[685]

BCOAPO also argues that access to capital under reasonable terms and conditions is already one of the considerations involved in determining the appropriate capital structure for each of FEI and FBC. As a result, BCOAPO submits that the inclusion of any market accessibility considerations in the determination of the appropriate ROE and the equity ratio is unjustifiable, as it results in "double-counting" and skews the results higher.[686] BCOAPO acknowledges that, in its final argument, FortisBC adopts Mr. Coyne's position that the flotation adjustment also serves to recognize that authorized equity ratios in Canada are less than those in the US.[687]

Overall, BCOAPO submits that the flotation cost adjustment of 50 bps is reasonable provided the BCUC recognizes that a portion of adjustment is to account for differences in the authorized equity ratios in Canada versus the US and this is recognized when setting the equity ratios for FEI and FBC.[688]

In its reply argument, FortisBC notes that interveners acknowledge that a fair return must account for flotation costs and financial flexibility.[689]

Panel Determination

Financial Flexibility

For the reasons set out below, the Panel finds that the appropriate way to account for required financial flexibility is to adjust the utility's capital structure.

[681] The CEC Final Argument, p. 57.
[682] Ibid.
[683] Ibid., p. 58.
[684] Ibid.
[685] BCOAPO Final Argument, p. 56.
[686] Ibid., pp. 56–57.
[687] BCOAPO Final Argument, p. 57.
[688] Ibid.
[689] FortisBC Reply Argument, p. 75.

The Panel accepts Dr. Lesser's statement that financial flexibility appears to be defined as having spare borrowing capacity and additional cash-on-hand, and thus, appears to be more related to the optimal capital structure and less one of the allowed ROE.[690]

However, Dr. Lesser concludes from this position that flexibility is best incorporated into the capital structure the BCUC sets for FEI and FBC by adjusting each utility's deemed equity ratios. He therefore does not consider an adder for financial flexibility to be just and reasonable.

Mr. Coyne does not appear to disagree. He submits that "if a Canadian regulator was looking to establish financial parity with US peers, then establishing comparable equity ratios (in the 50 percent to 52 percent range) and comparable allowed ROEs (9.5 percent to -10.0 percent range) would accomplish that objective[691] – and in doing so, would obviate the need for a 'financial flexibility' adder to the ROE, as the Canadian utility would now have financial comparability to its U.S. peers which do not have an equivalent adder".
Having found Dr. Lesser's approach to dealing with financial flexibility to be reasonable, the Panel will consider the issue of financial flexibility when it determines the approved capital structure for the two FortisBC public utilities.

Flotation Costs

The Panel accepts that any reasonable and prudently incurred flotation costs incurred by a public utility are recoverable from ratepayers, over and above the approved costs of capital. However, there is no evidence before the Panel that FEI or FBC incurs any flotation costs and therefore there are no costs to recover. Instead, FEI and FBC argue that because their parent incurs flotation costs on their behalf, FEI and FBC should be entitled to a Flotation Cost "adder".

The Panel disagrees. Generally speaking, costs incurred by an unregulated parent are not recoverable from a regulated subsidiary, unless those costs are directly allocated and billed to the subsidiary for services legitimately performed by the parent. This can include approved allocations of costs forecast or incurred by the parent on behalf of its regulated subsidiaries. However, there is no direct link evident to the Panel between the proposed flotation cost adder and actual costs incurred or expected to be incurred by the parent. For example, the adder will be the same if there is an annual equity injection by the parent or if such equity injection only occurs every five years or never occurs.

The Panel finds that the proposed flotation cost adder is too vague to be a just and reasonable expense recoverable from ratepayers. It is a very rough estimate of the actual flotation costs of shares issued by the parent when it issues its own shares to obtain the funds used to purchase the shares of its subsidiaries. Therefore, we reject the proposal to use the flotation cost adder.

FEI and FBC can request recovery of actual costs incurred by the parent by providing applicable invoices or other supporting documentation from the parent when FEI and FBC issue additional equity. That supporting documentation should provide enough detail to enable the BCUC to review it to determine that is a just and reasonable expenditure. Those expenditures, if and as incurred, can be recovered from the ratepayers of FEI, or

[690] Exhibit A2-20, BCUC IR 6.6.
[691] Exhibit B1-51, BCUC IR 1.1.

FBC as the case may be, following review and approval as part of each utility's Revenue Requirement process in the normal course.

6.3 Overall Capital Structure and ROE

Since experts, and the interveners' respective submissions on capital structure, financial model ROE results, adders and other adjustments, have already been reviewed in previous sections, this section will narrowly focus on jointly presenting the interveners' recommended capital structure and overall ROE figures, inclusive of all adders for flotation costs, financial flexibility and other considerations.

FortisBC submits that the BCUC should approve, in accordance with the Fair Return Standard, FEI's proposed common equity ratio of 45 percent with an ROE of 10.1 percent, and FBC's proposed common equity ratio of 40 percent with an ROE of 10.0 percent.[692] These figures are based on the US proxy groups and December 2021 data and consist of a simple average of Mr. Coyne's CAPM and Multi-Stage DCF model results. They are also inclusive of a 50-bps adder for flotation costs and financial flexibility.[693]

Mr. Coyne's recommended increase of FEI's equity ratio from 38.5 percent to 45.0 percent is due primarily to higher business risks as compared to 2016, which include accounting for "elevated Energy Transition risk in BC".[694] Further, Mr. Coyne submits that his recommended 45.0 percent equity ratio for FEI is the "approximate midpoint between average deemed equity ratio for Canadian investor-owned gas distribution companies and the authorized equity ratio for U.S. gas distribution companies since January 2020."[695]

Mr. Coyne explains that capital structure and the cost of common equity are closely linked in determining the fair return for regulated utilities. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks in the form of financial leverage to which their shareholders are exposed. Accordingly, regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.[696]

In its 2013 Decision, the BCUC stated:

> The Commission Panel confirms that the approval of rates to meet the FRS [Fair Return Standard] is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility.[697]

Because capital structure and ROE are inextricably linked, Mr. Coyne compares the weighted ROEs (authorized equity return multiplied by deemed equity ratio) for FEI and other large Canadian investor-owned gas distribution companies in Table 36.

[692] FortisBC Final Argument, p. 3.
[693] Exhibit B1-8-1, Figure 1 and Footnote 1, p. 4, Figure 2 and Footnote 2, p. 5.
[694] Exhibit B1-20, BCUC IR 76.1.1.1.
[695] Ibid., BCUC IR 71.8.
[696] Exhibit B1-8-1, Appendix C, p. 147.
[697] 2013 Decision, p. 12.

Table 36: Comparison of Authorized Equity Returns for FEI[698]

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Energy Inc. (existing)	8.75%	38.50%	3.37%
FortisBC Energy Inc. (proposed)	10.1%	45.00%	4.55%
ATCO Gas	8.50%	37.00%	3.15%
Enbridge Gas[224]	8.66%	36.00%	3.12%
Energir[225]	8.90%	38.50%	3.43%
Canadian Gas Average	8.69%	37.17%	3.23%
Canadian Gas Median	8.66%	37.00%	3.15%
U.S Gas LDC Average	9.48%	52.0%	4.93%
U.S. Gas Proxy Group Average	9.45%	53.4%	5.05%

As shown in the above table, FEI's current weighted equity return of 3.37 percent is within the range of other large gas distributors in Canada, with Energir having the highest weighed ROE. Mr. Coyne states that the proposed weighted ROE for FEI, at 4.55 percent, while higher than its Canadian peers, is justified by both the shift in overall industry risk due to the Energy Transition and updated market return data, as well as by averages for the US gas proxy group.[699]

Table 37 presents a comparison of authorized ROE, deemed equity ratios, and weighted ROEs for other Canadian investor-owned electric distribution companies. As shown in that table, FBC's weighted equity return, at 3.66 percent, is within the range of weighted equity returns in Canada, with Newfoundland Power at 3.83 percent having the highest weighted ROE. Mr. Coyne states that the proposed weighted ROE for FBC, at 4.00 percent, is more in line with FBC's current risk profile and current market data and moves the company closer to, but not within the range of, its US peers.[700]

Table 37: Comparison of Authorized Equity Returns for FBC[701]

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Inc. (existing)	9.15%	40.00%	3.66%
FortisBC Inc. (proposed)	10.0%	40.00%	4.00%
ATCO Electric	8.50%	37.00%	3.15%
Nova Scotia Power	9.00%	37.50%	3.38%
Hydro One Ltd.	8.66%	40.00%	3.34%
Newfoundland Power	8.50%	45.00%	3.83%
FortisAlberta	8.50%	37.00%	3.15%
Maritime Electric	9.35%	40.00%	3.74%
Canadian Electric Average	8.75%	39.42%	3.45%
Canadian Electric Median	8.50%	38.75%	3.36%
U.S. Electric Average	9.50%	49.64%	4.72%
U.S. Electric Proxy Group Average	9.59%	49.76%	4.77%

[698] Exhibit B1-8-1, Appendix C, Figure 64, p. 149.
[699] Ibid., Appendix C, pp. 149–150.
[700] Exhibit B1-8-1, Appendix C, p. 151.
[701] Ibid., Figure 65, p. 151.

Mr. Coyne differentiates business and financial risk in the following manner: business risk is inherent in a company's operations whereas financial risk relates to fixed obligations, but both are taken together to establish return requirements. Mr. Coyne states, "[b]usiness risk is the risk inherent in the company's operations, irrespective of how the company is financed. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner." [702] Mr. Coyne notes that the BCUC has typically found the level of business risk to be an important factor in determining the allowed capital structure, and bases his capital structure recommendations on this risk analysis. For financial risk, Mr. Coyne explains financial risk exists to the extent a company incurs fixed obligations in financing its operations as evidenced by the relative percentages of debt and equity in the capital structure.[703]

In comparison, Dr. Lesser describes business risks as generally reflected in the determination of the allowed ROE whereas financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt.[704] Dr. Lesser notes that business risk can encompass multiple dimensions and regulators would likely have to make subjective determinations of these differences, their significance, and appropriate ways to compensate for the differences. That might entail adjustments to allowed ROE or it might entail other mechanisms, such as creating or modifying balance account mechanisms.[705] Dr. Lesser states, one may have to adjust the equity return to account for certain business risks and adjust the capital structure to account for financial risk.[706] In contrast, Mr. Coyne describes the return to the equity investor as a function of both the equity ratio and the authorized ROE.[707]

Positions of Parties

The views of the Interveners on the appropriate capital structure for FEI and FBC are summarized in Table 38 and Table 39 below. For each of BCOAPO, the CEC and ICG, their recommended overall ROE figures in those two tables are inclusive of a 50-bps adder for financial flexibility and flotation cost. The BCUC calculates the interveners' resulting recommended weighted ROEs to facilitate the comparison with FortisBC's requests on capital structure and ROE.

Table 38: Capital Structure and ROE for FEI[708]

	Recommended Equity Component	Recommended Overall ROE	Recommended Weighted ROE
BCOAPO	40.00-42.00%	9.50%	3.80-3.99%
The CEC	40.00%	9.62%	3.85%
RCIA	40.00%	8.00-8.75%	3.20-3.50%

[702] Exhibit B1-8-1, Appendix C, p. 73.
[703] Ibid.
[704] Exhibit A2-24, BCOAPO IR 14.1.
[705] Exhibit A2-5, BCOAPO IR 10.
[706] Oral Hearing Transcript, Volume 4, p. 631.
[707] Exhibit B1-9, BCUC IR 60.2.
[708] BCOAPO Final Argument, pp. 65, 58, The CEC Final Argument, pp. 47, 43, RCIA Final Argument, pp. 31, 35, Recommended weighted ROE calculated by the BCUC.

Table 39: Capital Structure and ROE for FBC[709]

	Recommended Equity Component	Recommended ROE	Recommended Weighted ROE
ICG	38.50%	8.80%	3.39%
BCOAPO	40.00%	9.50%	3.80%
The CEC	40.00%	9.56%	3.82%
RCIA	40.00%	8.00-8.75%	3.20-3.50%

The following summarizes FortisBC's reply as it relates to interveners' submissions on the utilities' recommended capital structure, overall ROEs and/or the interplay between those two concepts.

ICG

With respect to ICG's submission, FortisBC highlights ICG's internal inconsistent reasoning to reach its low result:

i) On the one hand, ICG agrees that the BCUC should give the greatest weight to the North American proxy group when determining the ROE, which is, "no doubt, influenced by the fact that this tends to reduce FBC's ROE significantly relative to using the Canadian proxy group"; and

ii) On the other hand, ICG does the opposite to determine the common equity ratio as it advocates using the simple Canadian utilities median of 38.75 percent equity, rounded down without explanation to 38.5 percent, and giving "no weight" to the same U.S. proxy group companies that ICG advocates using for the ROE calculation. As the North American electric proxy group has an average equity ratio well above FBC's proposed equity ratio, ICG's approach tends to suppress the common equity ratio as well. FortisBC stresses that ICG's differing approaches are internally inconsistent because the common equity ratio and ROE and intertwined; ROE determinations are affected by the common equity ratio, and *vice versa*. FortisBC remarks that all the October 2022 ROE calculations based on the North American proxy group, which ICG wants to use, assume that the BCUC has accepted FBC's proposed common equity ratio of 40 percent. Even then, the U.S. electric proxy companies still have about 10 percent thicker equity on average (49.7 percent), such that the differential with the North American electric proxy group is substantial. FortisBC submits that FBC's ROE would be even more understated if the BCUC were to accept ICG's position of 38.5 percent equity. Applying a Hamada adjustment to the Lesser CAPM Results (30-day average stock prices and interest rates) for the North American proxy group at 38.5 percent equity increases the estimated ROE by 35 bps to 7.95 percent.[710]

Finally, FortisBC points out that ICG has not accounted for any size premium for FBC and offers no explanation for it. FortisBC stresses that both experts agree that the CAPM will understate ROE results for companies like FBC that are smaller than the proxy companies and reiterates that the size premium calculated by Mr. Coyne based on the Duff & Phelps approach is 105 bps.[711]

[709] ICG Final Argument, pp. 16,15, BCOAPO Final Argument, pp. 70, 58, The CEC Final Argument, pp. 51, 43, RCIA Final Argument, pp. 31, 35. Recommended weighted ROE calculated by the BCUC.
[710] FortisBC Reply Argument, pp. 55–56.
[711] Ibid., p. 55.

BCOAPO

With respect to BCOAPO's submission, FortisBC notes that BCOAPO endorses an ROE of 9.5 percent for both FEI and FBC, on 40 to 42 percent and 40 percent equity, respectively, inclusive of a 50-bps adjustment for flotation and financial flexibility, an adjustment for FEI and FBC's lower equity thickness, and a size premium for FBC. FortisBC states that BCOAPO's recommendations acknowledge that the cost of capital has increased since the BCUC last set FEI and FBC's respective ROEs but that BCOAPO's calculations still understate the required ROE due to its reliance on an implausibly low Lesser CAPM result and mathematical errors.[712] FortisBC states that the latter error skews BCOAPO's results downward significantly.[713]

Based on BCOAPO's methodology, FortisBC demonstrates how BCOAPO's recommended CAPM ROE should have been calculated as 9.51 percent instead of 9.01 percent, an error which carries forward when BCOAPO averages the CAPM and Multi-Stage DCF model results. The correction of BCOAPO's mathematical error in the overall average of BCOAPO's proposed CAPM and multi-stage DCF model for the BCOAPO-revised North American electric proxy group increases BCOAPO's ROE result from 9.04 percent to 9.29 percent.[714]

Furthermore, as noted in Section 5.2.2, FortisBC submits that the 12-bps upward adjustment for FEI that BCOAPO adds to account for its thinner proposed equity than the 45 percent basis for all the ROE model calculations is clearly insufficient. Applying a Hamada adjustment to Mr. Coyne's CAPM results for the BCOAPO-revised North American proxy group at 42 percent equity increases BCOAPO's estimated ROE by 45 bps. FortisBC submits that the ROE increase would be even larger at 40 percent (i.e. the lower end of the BCOAPO's recommended range for FEI's equity thickness).[715] Finally, FortisBC submits that BCOAPO miscalculates FBC's size premium and correcting that error alone yields an ROE of more than 10 percent. Indeed, FortisBC submits that the proper 105-bps size adjustment alone would increase BCOAPO's calculated ROE for FBC to approximately 10.09 percent, assuming 40 percent equity.[716]

The CEC

With respect to the CEC's submission, FortisBC stresses that the CEC's significant concessions, in terms of increased equity thickness and ROE for FEI and increased ROE for FBC, are indicative of the overwhelming body of evidence demonstrating that the cost of equity has increased since the BCUC last considered FEI and FBC's respective ROEs. However, FortisBC views the CEC's recommended ROEs as being understated in two respects.

The first relates to the 80-bps deduction which accounts for most of the difference between the CEC's and Mr. Coyne's respective recommendations. The second relates to the interplay between equity thickness and ROE. FortisBC points out that the modelling underlying the CEC's recommendations for FEI is premised on a 45 percent common equity ratio, but the CEC is recommending a 40 percent ratio. FortisBC states that both experts confirm that increasing the disparity between FEI's equity ratio and that of the proxy group will increase the required ROE. FortisBC points out that Mr. Coyne chooses not to include a Hamada adjustment to his CAPM results only because he also recommends to increase FEI's equity ratio to 45 percent, thus significantly

[712] FortisBC Reply Argument, p. 44.
[713] Ibid., p. 45.
[714] Ibid., p. 46.
[715] FortisBC Reply Argument, p. 46.
[716] Ibid., p. 47.

narrowing the equity disparity with the gas proxy groups. But FortisBC states that this logic will no longer hold at the CEC's recommended 40 percent equity for FEI and applying a Hamada adjustment to Mr. Coyne's CAPM results for the North American gas proxy group at 40 percent equity would increase the estimated ROE for FEI by 48 bps to 10.78 percent.[717]

RCIA

With respect to RCIA's submission, FortisBC points out that RCIA arrives at its proposed ROEs of 8.00 percent to 8.75 percent for both FEI and FBC by ignoring the Multi-Stage DCF model (and the higher results[718]) altogether, by applying unsupported downward adjustments to Mr. Coyne's CAPM results, by ignoring the most current data, and by failing to account for differentials in financial risk and size premium. FortisBC submits that updating RCIA's own calculations to reflect October 2022 data alone significantly closes the gap with Mr. Coyne's recommendations, and rectifying other shortcomings brings them further into alignment.[719]

As explained in Section 5.2.5, with the first adjustment, RCIA's CAPM-based ROE would increase to 9.43 percent, which is significantly higher than its proposed 8.00 percent to 8.75 percent. Averaging this 9.43 percent with the Multi-Stage DCF model results for the Canadian proxy group of 10.46 percent based on October 2022 data would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent on 45 percent common equity for FEI and 10.0 percent on 40 percent common equity for FBC.[720] Then, applying a Hamada adjustment to RCIA's own CAPM calculations, updated to October 2022 data for the Canadian proxy group at 40 percent equity, would increase the estimated ROE for FEI and FBC by 47 bps to 9.90 percent.[721] And adding a size premium for FBC, which Mr. Coyne calculates at 105 bps based on Duff & Phelps data, would further increase the CAPM ROE for FBC.[722]

Overall Panel Determination on Capital Structure and ROE

Deemed Equity Component

FortisBC proposes an equity thickness of 45.0 percent for FEI and 40.0 percent for FBC, while interveners recommend 40.0 percent to 42.0 percent for FEI and 38.5 percent to 40.0 percent for FBC. Mr. Coyne observes that his recommended 45.0 percent equity ratio for FEI is the approximate midpoint between the average equity ratio of Canadian investor-owned gas distribution companies and US gas distribution companies.

While the Panel views the 37.0 percent to 53.4 percent equity thickness of comparable Canadian and US gas utilities (see Table 36 above) as a possible range of equity thickness for FEI, this does not imply that any point within the range will meet the Fair Return Standard. The Panel is not convinced that determining a deemed equity component can be done in a precise manner such as taking an average between certain numbers. A capital structure that is optimal for FEI or FBC may not be optimal for other utilities. The Panel must assess the business risk, financial risk, and other items such as accounting for differences in leverage in the proxy group

[717] FortisBC Reply Argument, pp. 43–44.
[718] The Multi-Stage DCF model results are higher than the CAPM results based on October 2022 data, not December 2021 data.
[719] FortisBC Reply Argument, p. 47.
[720] FortisBC Reply Argument, pp. 50–51.
[721] 9.43% + 0.47% = 9.90%.
[722] FortisBC Reply Argument, p. 51.

companies used in the modelling (e.g. a Hamada adjustment in the CAPM results) and allowing for financial flexibility, all of which may be difficult to quantify when estimating the required equity component.

Further, Mr. Coyne's "midpoint" observation does not align with his recommendation for FBC's deemed equity ratio of 40.0 percent, where the Canadian electric average is 39.42 percent and the US electric proxy group average is 49.76 percent as shown in Table 37 above.

Throughout this decision, the Panel notes that certain factors should be considered as part of the capital structure determination, namely:

- Compensation to the shareholder for the business and financial risks of FEI and FBC (Sections 4.2 and 4.3).
- The approach to addressing the discrepancy in financial risk through an adjustment to the capital structure (Section 5.2.2).
- Consideration of financial flexibility to the extent that it is required for FEI and FBC to have spare borrowing capacity. However, Mr. Coyne submits that financial flexibility is not necessary if the regulator establishes comparable equity ratios in the 50 percent to 52 percent range and comparable ROEs in the 9.5 percent to 10.0 percent range (Section 6.2.2).
- Benefits of maintaining the current credit ratings of FEI and FBC (Section 4.1).

In Section 4 of this decision, we assess how business risk has changed since 2016 for FEI and 2013 for FBC from the perspective of their shareholder and investors. We discuss that Energy Transition risk for FEI is a real shareholder risk in Section 4.2, while other increased risk categories are largely borne by ratepayers. Overall, an increase in FEI's equity component is warranted to compensate for the increased risks faced by FEI's shareholder and investors.

The Panel recognizes that Dr. Lesser describes business risks to be generally reflected in the determination of the allowed ROE because financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt. However, there is no supporting evidence for his view. In contrast, Mr. Coyne's view is that there is a need to adjust either the capital structure or the ROE. Therefore, it follows that regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.

For practical reasons, given the inter-relationship of all these factors, the Panel will continue the approach of reflecting changes in business risks as adjustments to the capital structure, recognizing that it will also impact the ROE. This approach is consistent with past BCUC decisions and provides room for the exercise of informed judgment.

In determining the optimal capital structure for FEI, the only expert evidence is Mr. Coyne's recommendation of 45.0 percent and his cost of capital analysis is largely built around this 45.0 percent equity thickness. Further, Mr. Coyne chooses not to make Hamada adjustments to his own CAPM results because his recommended common equity ratio of 45.0 percent for FEI would "significantly narrow the equity disparity with the gas proxy

group."[723] The Panel agrees that any deviation from a 45.0 percent equity thickness, for example, setting FEI's equity thickness at the 40.0 percent to 42.0 percent range, may warrant a corresponding impact on the allowed ROE.

In the absence of contrary expert evidence and recognizing that FEI shareholder's real business risks, such as the impacts from the Energy Transition risk have increased since 2016, we accept Mr. Coyne's recommended 45.0 percent equity thickness for FEI. The Panel finds that the 45.0 percent equity thickness meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by our assessment of FEI's business risk. Further, as compared to FEI's current 38.5 percent equity thickness, an increase to 45.0 percent will maintain FEI's financial integrity.

The Panel now turns to financial leverage and financial flexibility. The Hamada adjustment and financial flexibility are partially related. The objective is to harmonize FEI and FBC's financial leverage to be comparable with peer proxy companies. For FEI, we acknowledge that 45.0 percent meets the Fair Return Standard and is supported by business risk assessment, comparable investments, and expert recommendation. In our view, a 45.0 percent equity component forms an optimal capital structure based on the evidence in Stage 1.

Further, since FortisBC's own expert acknowledges that 45.0 percent would "significantly narrow" the equity disparity and bring FEI's equity thickness towards the 50.0 percent to 52.0 percent range applicable to its proxy group, the Panel is not persuaded that increasing FEI's equity thickness beyond 45.0 percent to incorporate a further adjustment for financial flexibility or ring-fencing is required in order to meet the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FEI is 45.0 percent.**

For FBC, we note that FortisBC's proposed 40.0 percent equity thickness and interveners' positions are mostly aligned. Mr. Coyne also recommends 40.0 percent equity thickness for FBC. However, ICG submits that the BCUC should set FBC's equity thickness at 38.5 percent, which is based on the Canadian Electric median of 38.75 percent and submits that FBC's business risks are lower since 2013.[724] The Panel agrees with FortisBC that ICG's final arguments are unclear because on one hand, ICG submits that "the BCUC should place the greatest weight on the North American proxy group results"[725] but on the other hand, "the US proxy group should be no weight when determining FBC's equity ratio."[726] Therefore, we place no weight on ICG's recommendation to set FBC's deemed equity thickness at 38.5 percent.

As discussed in Section 4.3, the Panel finds that FBC's business risk overall has not changed materially since 2013. The Panel views that business risk assessment of FBC should be the primary factor to the determination of a fair capital structure. This is because we see that financial impacts, in part, result from our decision on the deemed capital structure. FBC has managed to maintain its current credit rating since 2013 at 40.0 percent equity thickness. Therefore, we find that no change in FBC's equity component within its current capital structure is warranted to reflect no material changes in its business risk.

Notwithstanding these findings, the Panel now needs to consider financial leverage and financial flexibility for FBC to determine whether any upward adjustment to its 40.0 percent equity thickness is warranted. FortisBC

[723] FortisBC Reply Argument, p. 43.
[724] ICG Final Argument, pp. 3–4.
[725] Ibid., p. 10.
[726] Ibid., p. 16.

and Mr. Coyne are not recommending any capital structure changes for FBC and have not explicitly recommended a size premium in the CAPM analysis for FBC.

While 40.0 percent equity thickness is in line with the Canadian electric utility average of 39.42 percent, it is much lower than the US electric proxy group average of 49.76 percent. We accept Mr. Coyne's observation that his FBC recommendation is in line with FBC's current risk profile, but not within the range of its US peers. In light of our decision to consider financial leverage and financial flexibility in the capital structure, we find that a modest upward adjustment in equity thickness of 1.0 percent for FBC is warranted to conform with the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FBC is 41.0 percent.**

Return on Equity

The Panel is persuaded by Dr. Lesser's view that, in addition to being anchored in financial theory and being transparent, models used by regulators to set the cost of capital for regulated utilities should ideally minimize reliance on subjective factors. Dr. Lesser states that 'subjective' adjustments to model results are those made without any underlying basis in financial theory and no empirical support, and he advises against these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with reasonable decision-making.

Previously in this decision, the Panel made certain determinations that are departures from, namely the 2013 and 2016 BCUC cost of capital decisions. One change worth highlighting is the Panel's determination to use North American proxy groups, based on a finding that using North American data, consisting of a reasonable mix of both Canadian and US comparators, is superior to using either Canadian proxy groups or US proxy groups alone.

Furthermore, the Panel accepts Mr. Coyne's beta estimates, which are Blume-adjusted, noting that both experts in this proceeding favour the use of Blume-adjusted betas and that none of the parties object to their use. The Panel is also reassured to see that empirical evidence exists to show that the Blume adjustment is applicable to all betas, ranging from a low of 0.50 to a high of 1.53. The Panel recognizes that the use of Blume-adjusted betas is a departure from the previous two BCUC cost of capital decisions and has the effect of increasing the CAPM ROE as the Blume-adjusted betas for Mr. Coyne's North American proxy group average 0.86, compared to a BCUC-accepted beta of 0.60 in the 2013 and 2016 Decisions.

Also, the Panel finds that it is appropriate to consider forward-looking estimates in determining the MRP and to base that forward-looking MRP on the Constant DCF model, which has been given equal weighting to the historical MRP. These determinations are also departures from previous BCUC decisions. In particular, the 2016 Decision placed more weight on historical MRP estimates than on the forward-looking ones and no weight on the DCF estimates of the forward-looking MRP (constant growth or Multi-Stage DCF). The Panel acknowledges that these determinations also increase the CAPM ROE relative to placing more weight on historical MRP or to using the Multi-Stage DCF model to estimate the forward-looking MRP.

Beyond these findings, the Panel takes the approach of making determinations that have a sound basis in financial theory, that are transparent and easily replicated, with minimal 'subjective' adjustments. The Panel agrees with Dr. Lesser and finds it preferable to get the allowed ROE value right based on the models rather than

adjusting the allowed ROE after the fact, such as adding adders for financial flexibility and flotation costs or considering other adjustments as suggested by some interveners.

To balance the fact that pure market-based models like the DCF model and CAPM tend to get whipsawed by volatile conditions in the market, which characterized much of the period during which evidence was filed in this proceeding, the Panel finds that relying on more models than just the CAPM and Multi-Stage DCF is especially important. Accordingly, the Panel determined earlier in this decision that considerable weight should also be given to the use of the Risk Premium Model, instead of simply using it as a reasonableness check as Mr. Coyne advocates.

Ultimately, the Panel finds that assigning an equal weighting to each of the three models is appropriate for the following reasons: 1) the Panel sees merit in all three models, recognizing their respective strengths and weaknesses, and behaviour under different market conditions; 2) the Panel would be hard pressed to say that one model is fundamentally superior to the others; and 3) the Panel sees no compelling reason to give anything other than equal weighting to each of the three models.

The following table summarizes the Panel's previous individual determinations related to the ROE estimates based on the CAPM, Multi-Stage DCF model, Risk Premium Model, and the flotation costs and financial flexibility adders to arrive at its ROE determination for FEI and FBC, respectively.

Table 40: Allowed ROE for FEI and FBC

Models	Revised North American Gas Proxy Group	Revised North American Electric Proxy Group
CAPM – excluding flotation costs and financial flexibility adder (see Section 5.2.5)	9.90%	9.77%
Multi-Stage DCF model – excluding flotation costs and financial flexibility adder (see Section 5.3.3)	8.93%	8.99%
Flotation costs and financial flexibility adders for the CAPM and Multi-Stage DCF models only (see Section 6.2)	0.00%	0.00%
Risk Premium Model (see Section 5.4.3)	10.12%	10.16%
Average of all three models	**9.65%**	**9.64%**

From a purely mathematical standpoint, FEI would have an allowed ROE that is 1 bps higher than FBC. However, the Panel does not view that such differentiation in allowed ROE is warranted. The difference in utility characteristics is already reflected in the deemed capital structure for FEI and FBC. **The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.**

For the reasons stated above, the Panel determines the following:

- **For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and**
- **For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.**

Although the allowed ROEs for both utilities are determined to be the same for FEI and FBC, the Panel notes that the reasoning behind the utilities' overall cost of capital determinations are fundamentally different. As a natural gas distribution utility, FEI's shareholder and investors are faced with higher business risk driven primarily by the Energy Transition. Hence, FEI's deemed equity component is higher than that of FBC. In contrast, while the Panel finds that FBC's business risks are similar since it was last reviewed, FBC is a relatively small utility with weaker financial metrics. Lastly, the financial models using the most recent October 2022 data and the appropriate proxy groups yielded very similar ROE results for both FEI and FBC.

FortisBC and Mr. Coyne introduce the weighted ROE concept, and the table below is a compilation of weighted ROEs presented by the parties compared to the Panel's decision.

Table 41: Comparison of Weighted ROEs for FEI and FBC

	FEI	FBC
Existing	3.37%	3.66%
Proposed	4.55%	4.00%
Canadian Average	3.23%	3.45%
U.S. Average	4.93%	4.72%
Proposed by interveners	3.20-3.99%	3.20-3.82%
Decision	9.65% * 45.0% = 4.34%	9.65% * 41.0% = 3.96%

Our decision falls within the range between the Canadian and US averages, as well as almost exactly halfway between the high-end of the interveners' recommendations and FortisBC's proposal. As explained in the reasons above, we find that the deemed equity thickness and allowed ROEs for each of FEI and FBC meet the Fair Return Standard. The Panel expects that our decision will fairly compensate investors' opportunity cost, maintain financial integrity of the utilities, and enable each utility to continue to attract new capital upon reasonable terms.

7.0 EFFECTIVE DATES AND STAGE 2 OF THE GCOC PROCEEDING

Having made our determinations on FEI and FBC's respective cost of capital, we now examine the appropriate timeline for the changes to come into effect. FEI and FBC currently have interim rates in place, effective January 1, 2023.[727] The BCUC invited parties to address the following:[728]

1. The effective dates for which FEI and FBC's cost of capital will take effect and the rationale; and
2. The timing and process to commence Stage 2.

The BCUC also invited further submissions on the effective date for all other utilities that use the Benchmark Utility to set their own cost of capital.[729]

[727] FEI Annual Review for 2023 Delivery Rates, Decision and Order G-352-22 dated December 5, 2022; FBC Application for Reconsideration and Variance of Order G-382-22, Decision and Order G-87-23 dated April 19, 2023.
[728] Exhibit A-26.
[729] Exhibit A-31.

FEI is the current benchmark (Benchmark Utility) for other utilities in BC that use a Benchmark Utility to set rates. In the April 2022 procedural conference, PNG, Corix, and RDE submitted that the choice of a Benchmark Utility is better addressed in Stage 2, after the BCUC determines FEI and FBC's cost of capital in Stage 1.[730]

As previously determined, in Stage 2, the Panel will consider, amongst other matters, whether FEI remains the appropriate default Benchmark Utility for some or all other utilities in BC, whether FBC is a more appropriate benchmark, or whether each utility's allowed ROE and deemed capital structure should be individually determined.

We summarize the parties' submissions below on the two issues identified above.

Positions of the Parties

Effective Dates for FEI and FBC

For FEI and FBC's cost of capital effective date, most parties support an effective date of January 1, 2023. FortisBC submits that January 1, 2023, reflects the evidence based on mid-2021 and December 2022 data of when the cost of capital analysis took place. Further, January 1, 2023, reflects current investor expectations based on recent data and would not delay the implementation on the utilities' right to earn a fair return.[731] Similarly, the CEC submits that January 1, 2023, would provide "equitable relief for FEI and other utilities as soon as possible" and "implementation can be factored into customer bills… to avoid having a larger catch-up."[732] ICG and RCIA also support the January 1, 2023 effective date.[733]

Nelson Hydro strongly disagrees with an effective date of January 1, 2023, and is "opposed to any retroactive rate increase for FBC,"[734] but does not propose a specific date other than "subsequent to a decision being made by the Panel." [735]

In response to Nelson Hydro, FortisBC states that the "January 1, 2023 implementation date is not "retroactive" in the legal sense, as FBC's rates are currently interim."[736] FortisBC argues that Nelson Hydro's approach "would contravene the Fair Return Standard"[737] and that the "legally permissible solution" is for Nelson Hydro to request approval for a deferral account (to capture the impacts of the change to FBC's cost of capital for 2023 on energy costs for recovery).[738]

[730] Order G-106-22, Reasons for Decision, p. 4.
[731] FortisBC Final Argument, p. 199.
[732] The CEC Final Argument, p. 60.
[733] ICG Final Argument, p. 18; RCIA Final Argument, p. 33.
[734] Nelson Hydro Final Argument, p. 1.
[735] Ibid., p. 2.
[736] FortisBC Reply Argument, p. 84.
[737] Ibid.
[738] Ibid.

Timing and Process to Commence Stage 2

FAES suggests commencing Stage 2 at a minimum of 60 days following the BCUC's issuance of this GCOC Stage 1 Decision. [739] At the time of its January 2023 final arguments, Nelson Hydro submits that the appropriate commencement of Stage 2 is summer of 2023 when it has more capacity available to participate. [740]
The CEC recommends scheduling Stage 2 "as quickly as possible so that implementations [sic] for all utilities can be done this year with smooth implementations [sic]."[741]

Effective Dates for Utilities that Use the Benchmark Utility to Set Rates

Stage 2 is expected to examine the cost of capital for all other utilities such as PNG, Corix, Creative Energy, Nelson Hydro, RDE, FAES, and others, with the exception of BC Hydro. The Panel discusses AMPC's submissions with respect to the latter in Section 8.3 of our decision.

Utilities and interveners submit that the BCUC should avoid retroactive ratemaking as a matter of regulatory principle.[742] Submissions regarding the mechanisms to implement any rate changes varied, ranging between the use of interim rates, deferral accounts, compliance filing for updates, or aligning all utilities' effective dates to be the same. For instance, Corix submits that if the BCUC sets the Benchmark Utility's cost of capital, effective January 1, 2023, then the effective date for other utilities that uses the Benchmark Utility should be:[743]

1. January 1, 2023 for utilities that have interim rates in place, effective January 1, 2023;
2. The first day of the month following GCOC Stage 1 Decision's issuance for utilities that do not have interim rates but have an existing deferral account that can be used to absorb the impact of the change in ROE or capital structure; or January 1, 2024.

Corix also submits that regardless of the FEI effective date, each utility can submit compliance filings to the BCUC seeking approval or acceptance depending on their specific circumstances to update their tariffs and implement rate changes as required.[744] RDE is of a similar view, advocating for the opportunity to submit a compliance filing.[745]

FAES notes that the use of the Benchmark Utility for rate setting is "inherently designed to facilitate automatic changing of the rates of return for those utilities if the BCUC approves a change in the Benchmark Utility."[746] The CEC submits that to the extent that the BCUC issues a decision for FEI or FBC, effective either January 1, 2023 or January 1, 2024, prior to the completion of Stage 2, then the utilities relying on the existing Benchmark should be similarly adjusted on January 1, 2023 or January 1, 2024, respectively.[747] Creative Energy submits that the appropriate effective date to make changes for utilities using the Benchmark Utility should be consistent with

[739] FAES Final Argument, p. 1.
[740] Nelson Hydro Final Argument, p. 2.
[741] The CEC Final Argument, p. 60; the CEC Submission dated May 31, 2023.
[742] RCIA Submission dated May 31, 2023, p. 1, BCOAPO Submission dated May 31, 2023, p. 1, Corix Submission dated May 31, 2023, p. 2.
[743] Corix Submission dated May 31, 2023, pp. 1–2.
[744] Corix Submission dated May 31, 2023, p. 3.
[745] RDE Submission dated May 31, 2023, p. 2.
[746] FAES Submission dated May 31, 2023, p. 3.
[747] The CEC Submission dated May 31, 2023, p. 1.

the date approved for FEI. The changes to rates should be made as soon as reasonably practical.[748] Nelson Hydro reiterates that FBC should not be permitted to utilize an effective date of January 1, 2023, for any changes to its cost of capital and that no changes should are warranted until the completion of the Stage 2. It submits that the fair and efficient implementation of rates for all utilities and their ratepayers should take place on a prospective basis only.[749]

With the implementation options available, utilities and interveners consider ratepayer impacts and the practicality of implementing rate changes. RCIA submits that implementing changes, effective January 1, 2024, allows for a more reasonable transition period and provides utilities and ratepayers more time to adapt to any changes.[750] PNG submits that implementing rate changes, effective January 1, 2024, will allow the other utilities to establish permanent rates for 2023. This provides rate stability and certainty for 2023 and will minimize rate impacts and amounts to be recovered from/refunded to ratepayers in the future.[751] PNG also argues that first applying other utilities' existing risk adjustments to FEI's new capital structure and ROE, and then applying the other utilities' new risk adjustment to the identified Benchmark Utility (or Utilities) will be administratively cumbersome and may cause unnecessary rate volatility for customers.[752] Similarly, RDE views that establishing new customer rates upon conclusion of Stage 1 will add significant regulatory burden and introduce inefficiency to the rate-setting process.[753] In contrast, Corix submits that delaying the implementation of changes until the completion of Stage 2 has a compounding effect and could result in a larger rate increase for customers as opposed to two smaller rate increases.[754]

FAES notes that the utilities and interveners propose a wide variety of opinions which reflect the unique characteristics of each utility. FAES submits that rate changes for each affected utility should occur independently according to their specific circumstances.[755]

Panel Determination

Effective Dates for FEI and FBC

The Panel agrees with FortisBC that the effective date for FEI and FBC's cost of capital should reflect the evidence examined throughout Stage 1. We note that the evidentiary record closed in December 2022. FEI and FBC already have interim rates as of January 1, 2023, in place awaiting the results of Stage 1. Thus, the earliest possible date to implement FEI and FBC's new cost of capital is January 1, 2023. We find that the effective date to implement changes should align with the period in which the evidence was examined to allow FortisBC to earn a fair return, and the date that best reflects the currency of that evidence is January 1, 2023.

The Panel acknowledges Nelson Hydro's opposition to implementing rate changes for FBC's cost of capital, effective January 1, 2023, on the basis that all utilities should implement rate changes on a prospective basis

[748] Creative Energy Submission dated May 31, 2023, p. 1.
[749] Nelson Hydro Submission dated May 31, 2023, pp. 1–2.
[750] RCIA Submission dated May 23, 2023, p. 1.
[751] PNG Submission dated May 31, 2023, p. 2.
[752] Ibid., p. 3.
[753] RDE Submission dated May 31, 2023, p. 2.
[754] Corix Submission dated May 31, 2023, p. 4.
[755] FAES Response dated June 14, 2023, pp. 1–2.

only. The BCUC sets rates prospectively subject to certain exceptions[756] as acknowledged by the courts such as in the *ATCO Gas & Pipelines Ltd. V. v Alberta (Energy & Utilities Board)* Decision.[757] However, we note that the BCUC had previously contemplated the possibility of a January 1, 2023 effective date, pending the results of Stage 1 and had approved interim rates for the FortisBC utilities for 2023 in the event that the BCUC determined that such effective date is appropriate. Therefore, we are not persuaded that FortisBC's cost of capital implementation should be delayed to 2024.

The Panel determines that the deemed capital structure and allowed ROE for FEI and FBC as set out in Section 6.3 of this decision be implemented, effective January 1, 2023. **Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved**.

Effective Dates for Utilities that Use the Benchmark Utility to Set Rates

As for other utilities that uses the Benchmark Utility to set their rates, the Panel concurs with FAES that there is a wide variety of opinions presented. We understand that each utility has its own preferences, and some utilities are undergoing their own rate proceedings and are at different stages. We also knowledge that absent specific exceptions, retroactive ratemaking is not permissible as a matter of regulatory principle. Furthermore, it would be unfair for utilities to retrospectively collect or refund customer monies without an appropriate mechanism for doing so or without adequate notice to ratepayers. However, while each utility's situation may be unique, some balance must be factored in to ensure consistency and fair treatment amongst all utilities.

In terms of the specific mechanism, the Panel considers that the benefits of establishing interim rates for all other utilities that use a Benchmark Utility to set their capital structure and equity return outweigh other mechanisms. Setting interim rates for all other utilities, effective January 1, 2024, allows the BCUC to make any adjustments at the conclusion of Stage 2. Ratepayers will be provided adequate notice that the rates they pay in 2024 will be subject to any changes resulting from Stage 2.

In the absence of notice to affected ratepayers of potential rate changes in 2023 arising from the BCUC's determinations in Stage 1, we are not persuaded that some utilities that already have interim rates in 2023 should be allowed to make rate adjustments in 2023, simply because they were granted interim rates, pending a final decision on permanent rates for each utility's respective rate proceedings. The same applies to some utilities that may already have regulatory deferral accounts that can capture timing differences in the allowed return.

Further, the establishment of any new deferral accounts can only capture differences on a prospective basis. In either case of using previously approved interim rates or deferral accounts, the Panel finds that customers are not given proper notice that the existing rates they are currently paying may change due to a pending GCOC decision. This is in direct contrast to FBC and FEI, which have flagged the issue of the effective date of the cost of capital throughout Stage 1 as a matter that required determination, and sought and received BCUC approval for interim 2023 rates during the utilities' Annual Review proceedings specifically for that purpose.

[756] For example, through interim rates or deferral accounts.

[757] Supreme Court of Canada, ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4 dated February 9, 2006, p. 179.

As for any automatic adjustments prior to and during Stage 2 due to changes to the Benchmark Utility's deemed capital structure and allowed ROE, the Panel agrees with RCIA, PNG and RDE that predictable rates and regulatory efficiency are important factors. Establishing interim rates, effective January 1, 2024, for all utilities that use the Benchmark Utility is just and reasonable. No adjustments are warranted to backdate a utility's earned return to January 1, 2023, or between the date of this GCOC Stage 1 Decision and January 1, 2024.

We also find that it would be inappropriate to increase other utilities' allowed ROE automatically based on their existing ROE premium in isolation, but without any consideration of their deemed capital structure. Further, we note PNG, Corix and RDE at the April 2022 procedural conference requested that the Benchmark Utility be determined after the outcome of Stage 1. Since then, no utilities have notified or requested of the BCUC in this proceeding that their rates be made interim in order to address the potential impacts of the BCUC's determinations on their rates in the various stages of the GCOC proceeding.

Therefore, the Panel directs that interim rates, effective January 1, 2024, be established on a refundable or recoverable basis for all other utilities that currently use the Benchmark Utility to set their capital structure and equity return, pending the BCUC's final decision on Stage 2. The BCUC will determine the manner by which any variance between approved interim rates and permanent rates, including interest if any, will be refunded or recovered at the time the BCUC renders its final decision on Stage 2.

For greater clarity, the interim rates to be established for utilities, effective January 1, 2024, do not apply to FBC, as its deemed capital structure and allowed ROE have been determined in Stage 1 and are effective January 1, 2023.

Timing and Process to Commence Stage 2

We agree with the CEC that Stage 2 should commence as soon as possible. FAES suggests that a minimum of 60 days following this GCOC Stage 1 Decision. Previous procedural orders established the scope of Stage 2.[758] Upon further review, the Panel amends item 1 by adding "neither" to reflect that no benchmark is also a plausible scenario.

PROCEEDING SCOPE – Stage 2

1. Whether the Benchmark Utility should be FEI, FBC, both, or neither. The groupings of public utilities for cost of capital determinations.

2. The establishment of the cost of capital for public utilities, or groups of public utilities, except for BC Hydro.

3. Whether any range or default in the equity component and equity risk premium is warranted for public utilities, or groups of public utilities.

4. Whether the determination of a deemed interest rate is warranted. If warranted, then:

    a) The circumstances where a deemed interest rate is required.

[758] Order G-106-22, Appendix C.

b) The determination of the deemed interest rate where required.

c) Whether an interest rate AAM is warranted.

d) The effective date for which the deemed interest rate or interest rate AAM will take effect.

5. Any items that may be identified during the proceeding to be considered in Stage 2. The Panel will communicate any additional items to participants.

The Panel remains of the view that the first step in Stage 2 is to address whether FEI should continue as the appropriate default Benchmark Utility for some or all other utilities in BC, whether FBC is a more appropriate benchmark, or whether each utility's allowed ROE and deemed capital structure should be individually determined. The BCUC has previously invited a round of submissions in June 2021.[759]

We acknowledge that utilities and interveners may wish to provide updated submissions given this GCOC Stage 1 Decision. However, recognizing that parties already have some background on the matter, we consider that an expedited regulatory timetable will help progress Stage 2 to examine and set the cost of capital for all other utilities in BC. Given this GCOC Stage 1 Decision, the Panel also invites parties to file submissions with respect to any appropriate modifications to the scope of Stage 2 that the BCUC previously established.

Therefore, the Panel confirms Stage 2 will commence 60 days after the date of this decision.

8.0 OTHER ISSUES

8.1 Automatic Adjustment Mechanism

The scope for GCOC Stage 1 as established by Order G-281-21 includes consideration of the potential reinstatement of an AAM formula as part of the ROE. [760] If the re-establishment of the ROE AAM formula is warranted, then the Panel must determine: (a) the specifications of the ROE AAM formula; (b) the frequency with which the ROE AAM formula will apply (i.e. annually or some other frequency) and the entities to which the AAM will apply; and (c) the date for which the ROE AAM formula will take effect.[761]
An AAM represents a formulaic approach to setting the ROE of the Benchmark Utility annually between ROE proceedings.[762]

In 1994, the BCUC first implemented an AAM based on changes to long-term Canada bond rates,[763] which underwent various changes and iterations[764] until 2009 when it was eliminated. That elimination was based on the BCUC's determination at that time that the AAM would not have provided an ROE that met the Fair Return Standard.[765]

[759] Order G-183-21.
[760] Exhibit A-8, Appendix B to BCUC Order G-281-21, p. 1 of 2.
[761] Ibid.
[762] BCUC 2013 GCOC Stage 1, Letter L-53-13, Appendix A, p. 1.
[763] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd. -- Decision and Order G-35-94, June 10, 1994.
[764] Exhibit B1-8, Table 9-1, p. 57.
[765] Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure (2009 TGI ROE), Decision to Order G-158-09, p. 72.

In 2013, the AAM was re-instituted on the basis that it offered the potential for regulatory efficiency and would better meet the Fair Return Standard than giving no consideration to market changes over the period between ROE proceedings.[766] The BCUC established a two-variable model taking into account utility bond spreads, as well as long-term Canada Bond yields.[767] However, in recognition of the effect of monetary policy on bond rates, the BCUC directed any implementation of the AAM be subject to an actual long-term Canada bond yield of 3.8 percent being met or exceeded (estimate of 3.8 percent was deemed reasonable by the BCUC and was within the relatively narrow range of estimates presented by all experts).[768] Therefore, the AAM formula would only apply if the long Canada bond yield was above 3.8 percent.[769]

In 2016, the BCUC suspended further use of an AAM as a mechanism to adjust ROE on an annual basis, as the BCUC was not persuaded that the AAM was appropriate given "uncertain" economic conditions, nor would it necessarily result in an ROE that would meet the Fair Return Standard given it does not reflect all items that affect a utility's ROE.[770] Nonetheless, BCUC indicated that it continued to hold the view that an effective AAM can be a useful tool in providing an updating mechanism for ROE, as this would eliminate some of the need for lengthy and expensive formal reviews. The BCUC suggested that once there is a return to more certain economic conditions with more normal interest rates, re-implementation of an AAM would be worthy of further consideration.[771]

In the current proceeding, FortisBC notes various drawbacks of the AAM: (i) it is not guaranteed to result in regulatory efficiency; (ii) it does not capture all factors that affect a utility's cost of capital such as an individual company's financial and business risk, proxy companies' earnings growth, and beta values; and (iii) the AAM formula is based on historical relationships that are not guaranteed to hold in future years, especially in uncertain capital markets.[772] Consistent with previous proceedings, FortisBC believes that an AAM formula cannot capture all of the changes facing a utility's cost of capital and it can yield a return that does not meet the Fair Return Standard.[773] FortisBC notes this is particularly true in the current economy where monetary and fiscal policies in response to the COVID-19 pandemic have resulted in significant uncertainty in capital markets that do not reflect the historical relationship between interest rates and equity returns.[774]

Mr. Coyne submits that the two-variable AAM formula from the 2013 GCOC proceeding is limited to changes in government bond yields and utility credit spreads, which are not the only relevant factors in determining the cost of equity for regulated utilities.[775] He further notes that the two-variable AAM formula from the 2013 GCOC proceeding would not reflect changes in other factors such as company size, fuel source, scope and business risk profile.[776] Mr. Coyne notes that he is not aware of an ROE formula that considers or adjusts for changes in capital structure; the capital structure remains fixed until the next full rate case.[777] Mr. Coyne performed a

[766] 2013 Decision, p. 88.
[767] Ibid., p. 90.
[768] Ibid., p. 91.
[769] Ibid.
[770] 2016 Decision, p. 89.
[771] 2016 Decision, p. 89.
[772] Exhibit B1-8, Section 9.2, pp. 58–61.
[773] Ibid., p. 60.
[774] Exhibit B1-8, Section 9.2, pp. 60–61, Exhibit B1-9, BCUC IR 61.2.
[775] Exhibit B1-9, BCUC IR 61.1.
[776] Ibid.
[777] Exhibit B1-9, BCUC IR 61.4.

jurisdictional review which indicates that AAMs are no longer a common approach in Canada.[778] Mr. Coyne concludes that periodic rate hearings remain the only reliable method for determination of utility ROEs given that all formulaic approaches run the risk of deviation from a fair return.[779] Mr. Coyne does note that if the BCUC were to determine that an AAM is appropriate, he would recommend that the BCUC establish an additional process to determine the correct formula given that developing an adjustment formula is a very detailed process that is better accomplished through input from regulated utilities and stakeholders.[780]

Dr. Lesser notes the greatest strength of the AAM is its simplicity. Dr. Lesser also notes certain weaknesses of the AAM, including (i) this same simplicity may not meet the Fair Return Standard and does not reflect other changes that affect cost of capital; and (ii) the degree of subjectivity required in determining the functional form of the AAM.[781]

FortisBC notes that bond spreads are still below the 3.8 percent trigger point in the previous AAM, which was implemented by the BCUC to recognize the potential for downward bias in ROE results when bond spreads are low.[782] FortisBC submits that there is little benefit in approving an AAM in the current proceeding due to the uncertainty of its applicability.[783] FortisBC concludes that the BCUC should continue to use periodic regulatory proceedings to set ROE, rather than implementing an AAM.[784]

Positions of the Parties

Interveners offer differing views. RCIA supports the introduction of an AAM in the current proceeding, the CEC supports the introduction of an AAM in the current proceeding but in the second stage, BCOAPO supports the concept of an AAM but not the introduction of one in the current proceeding, and ICG does not support an AAM.[785]

RCIA supports the use of an AAM, disagreeing with FortisBC.[786] RCIA states that the AAM developed by the BCUC in 2013 is akin to the basic CAPM and incorporates changes in the underlying risk-free rate to calculate the premium above the risk-free rate a utility would need to meet the Fair Return Standard.[787] RCIA cites Mr. Coyne's statements that based upon the bond yield alone, the regression model predicts 86 percent and 82 percent of the variance in approved ROE in Canada and the US, respectively.[788] RCIA states that the CAPM is a relatively simple model with only three input parameters (risk-free rate, market risk premium, and beta) producing highly reliable results.[789] Therefore, RCIA submits it is viable to re-establish a CAPM-type AAM that reliably and efficiently meets the Fair Return Standard within the next two to four years, and supports using the

[778] Exhibit B1-8-1, Appendix C, Concentric Report, pp. 153–154, Exhibit 1-9, BCUC IR 61.6–61.10.
[779] Exhibit B1-8-1, Appendix C, Concentric Report, p. 154.
[780] Exhibit B1-9, BCUC IR 61.6–61.10.
[781] Exhibit A2-3, Lesser Report, p. 92.
[782] FortisBC Final Argument, p. 198.
[783] FortisBC Final Argument, p. 198.
[784] Ibid., p. 197.
[785] RCIA Final Argument, pp. 32–33, The CEC Final Argument, pp. 59–60, BCOAPO Final Argument, pp. 71–72, ICG Final Argument, pp. 17–18.
[786] RCIA Final Argument, p. 33.
[787] Ibid.
[788] Ibid.
[789] Ibid.

previously approved 2013 formula for any interim period prior to the next GCOC hearing.[790] Furthermore, RCIA recommends that the benchmark ROE calculated by the AAM, with annual updates, apply to all utilities, with differences in utility risk profiles being addressed through bespoke equity thicknesses for each utility.[791] RCIA also submits that the reintroduction of the AAM in BC is appropriate to facilitate regulatory efficiency.[792]

The CEC states that the Risk Premium Model demonstrates a high degree of correlation between the changes in government bond rates and the appropriate ROE for utilities.[793] The CEC submits that it would be appropriate for the BCUC to direct a move toward establishing an AAM for the ROE estimates for FEI, which can then enable adjustments to all BC utilities[794] and provide regulatory efficiency, simplicity, and understandability. [795] The CEC submits that a simple straight-line formula through the historical data will establish a reasonable basis for adjusting components of the basis for establishing the ROEs for utilities.[796] The CEC recommends that where it had previously established economic and financial conditions with respect to bond prices that would not work as well with a straight-line formula, the BCUC should solicit further input with respect to a formula at the tail which could suitably accommodate a very low bond rate with a bend in the straight-line curve.[797] The CEC recommends setting a trigger amount for implementing a change if the risk premium falls outside of the straight-line formula by more than a fixed number of basis points (say 20 bps) to avoid minor changes that would not be material for FEI's financial standing in the capital markets. [798]

The CEC also recommends that the BCUC task FEI with reporting requirements and makes suggestions on the review process. The CEC recommends that the BCUC task FEI with establishing the formulas for review as a compliance requirement[799] and also task FEI to review the AAM with its credit rating agencies so that the BCUC can consider both the formula and the credit rating agency view.[800] With respect to process, the CEC submits that the BCUC could use a simple annual streamlined review process to review the implementation with the utilities and interveners before finalizing the implementation through FEI.[801] The CEC recommends an annual review process so that the need to implement a change is not too frequent. [802]

BCOAPO continues to support the use of an AAM but it does acknowledge the previous BCUC concerns about the difficulty establishing such a mechanism when economic conditions are uncertain and the evidence in this proceeding is clear: current economic and capital market conditions are both uncertain and volatile.[803] As result, BCOAPO accepts that now is not likely the appropriate time to attempt to design and implement an AAM.[804]

[790] RCIA Final Argument, p. 33.
[791] Ibid., pp. 32–33.
[792] Ibid., p. 32.
[793] The CEC Final Argument, p. 59.
[794] Ibid.
[795] Ibid.
[796] Ibid.
[797] The CEC Final Argument, p. 60.
[798] Ibid.
[799] Ibid., p. 59.
[800] Ibid.
[801] Ibid.
[802] Ibid., p. 60.
[803] BCOAPO Final Argument, pp. 71–72.
[804] Ibid.

ICG does not support an AAM.[805] ICG cites Dr. Lesser's statements that if an AAM is used to adjust the allowed ROE for the benchmark, then the risk adjustments for the other utilities may need to be adjusted.[806]

In response to RCIA, FortisBC notes that RCIA's suggestion to update the 2013 AAM as soon as reasonably possible is inconsistent with the 2016 Decision that suspended further use of an AAM in part due to economic uncertainty.[807] FortisBC notes that the conditions of economic uncertainty noted in 2016 continue to be a relevant consideration in the current proceeding that RCIA did not address in its final argument.[808]

FortisBC also states that the RCIA is incorrect in stating that the 2013 AAM is no less sophisticated than the models presented by FortisBC.[809] FortisBC asserts that Mr. Coyne's analysis contains multiple models and is in no way akin to the output of the 2013 AAM which is a two-variable model, based on long Canada bond yields and the spread between long Canada bonds and A-rated utility corporate bonds.[810]

In response to the CEC, FortisBC notes that there is little utility in examining an AAM in the current period of high inflation and economic uncertainty.[811] FortisBC submits that attempts to mechanize the cost of capital may lead to ROE values that do not meet the Fair Return Standard, particularly in uncertain market conditions.[812] However, FortisBC notes that should the BCUC determine that the reintroduction of an AAM warrants consideration at this time, FortisBC agrees with the CEC that it would be more appropriately considered in a further stage.[813]

Panel Discussion

The Panel supports the BCUC's determination in the 2016 Decision that suspended further use of an AAM in part due to economic uncertainty.[814] As noted by FortisBC, the conditions of economic uncertainty observed in 2016 continue to be a relevant consideration in the current proceeding. The Panel shares the BCUC's concerns about the appropriateness of using AAM in "uncertain" economic conditions. When coupled with the current high inflationary environment, there is a real potential for an AAM to fail to meet the Fair Return Standard since it does not reflect all items that could potentially affect a utility's ROE.

As observed historically, the use of an AAM in an ultra-low interest rate environment is complex. While the current interest-rate environment may not be characterized as ultra-low, the reinstatement of an AAM would nonetheless entail a review and potential resetting of the previously BCUC-approved 3.8 percent interest rate threshold. As no party has offered any evidence with respect to the latter issue in this proceeding, we would have to reopen the evidentiary record in order to obtain evidence and submissions on this, which would result in a delay which we consider unwarranted in view of the length of this proceeding to date.

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[805] ICG Final Argument, p. 17.
[806] Ibid., pp. 17–18.
[807] FortisBC Reply Argument, pp. 80–81.
[808] Ibid.
[809] Ibid., p. 81.
[810] Ibid., p. 81.
[811] FortisBC Reply Argument, p. 80.
[812] Ibid.
[813] Ibid.
[814] Ibid., pp. 80–81.

We also note that while the previous AAM was based on changes in interest rates, ROE can be impacted by many other factors beyond interest rates. As Dr. Lesser cautions, the simplicity of an AAM fails to address other changes that affect cost of capital, depends on the subjectivity in establishing an appropriate formula, and risks not achieving the Fair Return Standard. Overall, we find that any regulatory efficiency that can be gained from the application of an AAM formula to avoid another full scale review of ROE is offset by these weaknesses. Furthermore, the latter has the benefit of providing parties with the opportunity to engage in a more transparent and thorough review of ROE whenever changes are required to reflect new circumstances.

Accordingly, we decline to reinstate the application of an AAM formula in favour of periodic regulatory reviews to set ROE, which we consider to be a better forum for ensuring that a utility's ROE meets the Fair Return Standard than reliance on a formula which may not accurately reflect all relevant factors. Having so determined, we see no need to deal with the specifics of any potential AAM formula and its application in this proceeding.

8.2 Off-Ramp / Trigger for Future Applications

The scope of Stage 1 includes consideration of "[t]he criteria, off-ramps, or other triggers to warrant a future cost of capital proceeding."[815]
FortisBC submits that the BCUC should not establish a trigger in advance.[816] FortisBC is unaware of any regulator that considers pre-defined triggers or criteria for future applications.[817] There are various factors that can impact investors' opportunity cost. Mr. Coyne submits that periodic cost of capital proceedings every three to five years is the best approach to ensure that the authorized return remains appropriate for regulated utilities, including those in BC.[818]

Positions of the Parties

FortisBC submits that a periodic review is appropriate and that there should be no establishment of a trigger, as there is no basis to rely on the variance between realized and allowed ROEs to initiate a cost of capital proceeding.[819]

In contrast, the CEC recommends a trigger for another GCOC proceeding in the event that any utility notifies the BCUC of "conditions that would impact its credit ratings" and establishes evidence that it is "seriously compromised in efforts to obtain needed capital."[820] Furthermore, the CEC recommends that triggering another GCOC proceeding may become "unnecessary for an indefinite time into the future provided the Commission enables processes for modifications to the AAM process that may be considered annually as improvements to the initially defined AAM," which it submits to be "a direct solution."[821] In reply, FortisBC agrees with CEC's recommendation that it should be open at all times for a Benchmark Utility to approach the BCUC with a justified request for a new GCOC and complete overhaul of the cost of capital regime, including the need to discard an AAM that cannot be suitably adjusted to deliver a fair return.[822]

[815] Order G-106-22 dated April 21, 2022.
[816] Exhibit B1-8, p. 62.
[817] Ibid., p. 7.
[818] Exhibit B1-8, p. 62, Exhibit B1-8-1, Appendix C, p. 156.
[819] FortisBC Final Argument, pp. 198–199.
[820] The CEC Final Argument, p. 60.
[821] Ibid.
[822] FortisBC Reply Argument, p. 82.

BCOAPO submits that if appropriate triggers cannot be established then another cost of capital proceeding should be scheduled no later than in three years' time or the BCUC should, on a similar timeline, establish a regulatory process to determine whether economic and market conditions have changed sufficiently to warrant a full review.[823]

In response to BCOAPO, FortisBC argues that "the BCUC should not establish a trigger for future cost of capital proceedings in advance."[824] FortisBC emphasizes that maintaining flexibility over the timing of the next review allows for a more appropriate response to business and capital market factors affecting the cost of capital for utilities that are inherently dynamic.[825] Furthermore, FortisBC explains that "the three-year timeline that BCOAPO suggests is too short; the BCUC has generally considered FEI's cost of capital every five years."[826]

RCIA submits that the next GCOC proceeding should be deferred to 2025 or later, noting that the underlying assumptions and method approved in this proceeding are "unlikely to change in the short term."[827] In response to RCIA, FortisBC agrees "to the extent that it implies that another proceeding should not be currently scheduled for the immediate future." However, it emphasizes that "2025 would be too early for a further periodic review."[828] Similar to its response to BCOAPO, FortisBC also notes that the BCUC has generally considered FEI's cost of capital every five years.[829]

Panel Determination

Nothing in the UCA prescribes a statutory timeframe for reviewing a utility's cost of capital. The BCUC has the power to initiate a cost of capital review at any time within its discretion, as it did in this instance. Similarly, a utility can apply to the BCUC for review of its cost of capital at any time.

While the BCUC in the 2013 GCOC proceeding indicated that it would review FEI's cost of capital in three years, we do not see the need to be prescriptive in this instance about the timing of the next review. We note that in any event, both FEI and FBC are currently under a multi-year rate plan which includes an off-ramp which is designed as a safeguard to protect the utility and ratepayers against potential unintended consequences (such as windfall surplus or losses) and is triggered if earnings in any one year vary from the approved ROE by +/- 150 bps. That plan expires at the end of 2024 and if there are material changes to markets or economic conditions after that affecting the utilities' ROE, we anticipate that either the BCUC or the utility will initiate a review of any changes at that time.

That said, we view that periodic reviews of utilities' cost of capital are desirable in ensuring that utilities continue to have the opportunity to earn a fair return based on their ROE and cost of capital despite changes in circumstances. At the same time, we recognize that such reviews entail significant investments of time and effort on the part of participants and should not be undertaken except where warranted.

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[823] BCOAPO Final Argument, p. 72.
[824] FortisBC Reply Argument, p. 82.
[825] Ibid., p. 83.
[826] Ibid.
[827] RCIA Final Argument, p. 34.
[828] FortisBC Reply Argument, p. 82.
[829] Ibid., p. 83.

As for determining specific triggers that would prompt a cost of capital review, we see no merit to doing so in the absence of any evidence or submissions from parties as to what may be appropriate objective triggers. We agree with FortisBC that maintaining overall flexibility over the timing of the next cost of capital review is desirable as a more appropriate response to dynamic market and business factors that are not always foreseeable. For the same reason, we do not consider it particularly helpful to limit the triggers for review to specific occurrences which are only at best speculative.

8.3 AMPC Request Regarding BC Hydro

AMPC represents members of BC Hydro's industrial customers and submits that shareholder return is one of the most important issues impacting electricity competitiveness in BC. When the BCUC invited submissions from parties regarding the effective date for all other utilities that use the Benchmark Utility to set their own cost of capital, AMPC took the opportunity to request the BCUC to determine that "if BC Hydro's forthcoming rate of return application is based on the benchmark utility it will be deemed incomplete and rejected pending evidence that considers BC Hydro's full context as an instrument of government policy."[830]

In reply, BC Hydro submits that it is procedurally unfair for AMPC to request the BCUC to decide on BC Hydro's forthcoming cost of capital application before it is even filed. BC Hydro's cost of capital application should be considered by the panel appointed to that proceeding.[831]

Panel Discussion

We decline AMPC's request to make any determination on BC Hydro's future cost of capital application. The evidence presented before us in Stage 1 relates to setting FEI and FBC's respective capital structure and equity return, not BC Hydro or any other utility. The BCUC in its BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Decision directed BC Hydro to file a cost of capital application, effective April 1, 2025, by no later than April 1, 2024.[832] AMPC is encouraged to participate and share its views in that future proceeding.

9.0 SUMMARY OF DIRECTIVES

This summary is provided for the convenience of readers. In the event of any difference between the Directives in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	**Page No.**
1.	The Panel finds that FEI's overall business risk has increased since 2016.	50

[830] AMPC Submission dated May 31, 2023, pp. 1–2.

[831] BC Hydro Response dated June 14, 2023, p. 2.

[832] BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, Decision and Order G-91-23 dated April 21, 2023, p. 10.

	Directive	Page No.
2.	The Panel finds that FBC's business risk overall has not changed materially since 2013.	63
3.	The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.	136
4.	The Panel determines the following: • For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and • For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.	136
5.	Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.	141

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of September 2023.

Original signed by:

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D. M. Morton
Panel Chair / Commissioner

Original signed by:

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A. K. Fung, KC
Commissioner

Original signed by:

_____

K. A. Keilty
Commissioner

Original signed by:

_____

T. A. Loski
Commissioner

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ORDER NUMBER
G-236-23

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Utilities Commission
Generic Cost of Capital Proceeding

BEFORE:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

on September 5, 2023

ORDER

WHEREAS:

A. By Order G-66-21 dated March 8, 2021, pursuant to section 82 of the *Utilities Commission Act* (UCA), the British Columbia Utilities Commission (BCUC) established a Generic Cost of Capital (GCOC) proceeding;

B. By Orders G-66-21, G-156-21, G-183-21, G-205-21, G-231-21, G-281-21, G-288-21, G-106-22, G-217-22A, and G-327-22A, the BCUC established a regulatory timetable and scope for the GCOC proceeding;

C. The GCOC proceeding is being conducted in two stages. Stage 1 of the GCOC proceeding will determine the deemed capital structure and allowed return on equity (ROE) of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC). Stage 2 will determine matters related to the Benchmark Utility and establish the cost of capital for other utilities in British Columbia;

D. The following parties participated in Stage 1 of the GCOC proceeding: FEI, FBC, Corix Multi Utility Services Inc. (Corix), Pacific Northern Gas Ltd. (PNG), River District Energy (RDE), British Columbia Hydro and Power Authority (BC Hydro), Boralex Ocean Falls Limited Partnership (Boralex), FortisBC Alternative Energy Service Inc. (FAES), Nelson Hydro, Kyuquot Power Ltd. (KPL), Creative Energy Vancouver Platforms Inc. (Creative Energy) Residential Consumer Intervener Association (RCIA), Movement of United Professionals (MoveUP), Clean Energy Association of BC (CEABC), Association of Major Power Customers of BC (AMPC), Industrial Customers Group (ICG), Commercial Energy Consumers Association of British Columbia (the CEC), and British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO);

E. The BCUC retained Dr. Jonathan A. Lesser of Continental Economics Inc. (Dr. Lesser) as an independent cost of capital technical expert in the GCOC proceeding. FortisBC retained Mr. James Coyne of Concentric Energy Advisors Inc. (Mr. Coyne) to provide an estimate of the cost of capital for FEI and FBC;

F. In its evidence dated January 31, 2022, pursuant to sections 59 to 61 of the UCA, FortisBC sought BCUC approval of the following:

   i. For FEI, approval of a capital structure consisting of 45 percent common equity and 55 percent debt, and a return on common equity of 10.1 percent.

   ii. For FBC, approval of a capital structure consisting of 40 percent common equity and 60 percent debt, and a return on common equity of 10.0 percent.

G. The regulatory review process for Stage 1 of the GCOC proceeding included two rounds of information requests (IRs) to FortisBC, one round of IRs to Dr. Lesser on Mr. Coyne's evidence, FortisBC rebuttal evidence on Dr. Lesser's IR responses, an oral hearing, final arguments, and further submissions regarding the implementation of utilities' rates; and

H. The BCUC has reviewed the submissions, evidence and arguments filed in Stage 1 of the GCOC proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the UCA, the BCUC orders as follows:

1. For FEI, the deemed equity component is 45.0 percent and the allowed ROE is 9.65 percent, effective January 1, 2023.

2. For FBC, the deemed equity component is 41.0 percent and the allowed ROE is 9.65 percent, effective January 1, 2023.

3. FEI and FBC are directed to file, within 30 days of the date of this order, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.

4. Interim rates are established, effective January 1, 2024, on a refundable or recoverable basis, for all other utilities, except FBC, that currently use the Benchmark Utility to set their capital structure and equity return pending the BCUC's final decision on Stage 2 of the GCOC proceeding.

5. Stage 2 of the GCOC proceeding is to commence 60 days after the date of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of September 2023.

BY ORDER

Original signed by:

D.M. Morton
Commissioner

British Columbia Utilities Commission
Generic Cost of Capital Proceeding

GLOSSARY AND ARCRONYMS

2013 Decision	BCUC 2013 Generic Cost of Capital Stage 1, Order G-75-13 and Decision dated May 10, 2013
2014 Decision	BCUC 2013 Generic Cost of Capital, Order G-47-14 and Decision dated March 25, 2014
2016 Decision	FEI Application for its Common Equity Component and Return on Equity for 2016, Order G-129-16 and Decision dated August 10, 2016
AAM	Automatic Adjustment Mechanism
AMPC	Association of Major Power Customers of BC
AUC	Alberta Utilities Commission
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society
BCUC	British Columbia Utilities Commission
BCUC 2013 GCOC proceeding	Collectively, Stage 1 and Stage 2 of the BCUC 2013 Generic Cost of Capital proceeding
Benchmark Utility	FortisBC Energy Inc. is the current benchmark for other utilities in BC that use a Benchmark Utility to set their rates
Boralex	Boralex Ocean Falls Limited Partnership
bps	Basis points
CAPM	Capital Asset Pricing Model
CEABC	Clean Energy Association of BC
COC	Cost of Capital
Concentric	Concentric Energy Advisors Inc.
Continental Economics	Continental Economics, Inc.
Corix	Corix Multi Utility Services Inc.
CPI	Consumer Price Index
Creative Energy	Creative Energy Vancouver Platforms Inc.
CRSP	Center for Research in Security Prices
DBRS	DBRS Morningstar, credit rating agency
DCF	Discounted cash flow
DPS	Dividend per share
Dr. Lesser	Dr. Jonathan A. Lesser of Continental Economics, Inc.
Dr. Lesser's Report	Regulated Utility Cost of Capital: Theory and Canadian Practice Report dated August 4, 2021, by Dr. Jonathan A. Lesser of Continental Economics, Inc.
EPS	Earnings per share
ESG	Environmental, social and governance
EV	Electric vehicle
FAES	FortisBC Alternative Energy Service Inc.
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.

FEI 2016 COC proceeding	FEI Application for its Common Equity Component and Return on Equity for 2016
FERC	Federal Energy Regulatory Commission
FortisBC	collectively, FEI and FBC
FortisBC's Evidence	Filing of evidence by FBC and FEI, including Evidence of Mr. James Coyne of Concentric Energy Advisors Inc.
FPIC	Free, prior and informed consent
GCOC	Generic Cost of Capital
GDP	Gross domestic product
IBES	Institutional Brokers' Estimate System
ICG	Industrial Customers Group
IR	Information Request
KPL	Kyuquot Power Ltd.
LNG	Liquefied natural gas
LTGRP	Long Term Gas Resource Plan
Moody's	Moody's Investors Service
MoveUP	Movement of United Professionals
Mr. Coyne	Mr. James Coyne of Concentric Energy Advisors Inc.
MRP	Market Risk Premium
MRS	Mandatory Reliability Standards
O&M	Operations and maintenance
PNG	Pacific Northern Gas Ltd.
RCIA	Residential Consumer Intervener Association
RDE	River District Energy
rf	the risk-free rate of return
rm	the required return for the market as a whole
Roadmap	CleanBC Roadmap to 2030
ROE	Return on Equity
S&P	Standard &Poor's Global Ratings
Stage 1	First stage of this GCOC proceeding
Stage 2	Second stage of this GCOC proceeding
The CEC	Commercial Energy Consumers Association of British Columbia
TSX	Toronto Stock Exchange
UCA	*Utilities Commission Act*
UPC	Use per customer
US	United States

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

British Columbia Utilities Commission
Generic Cost of Capital

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated January 18, 2021 – British Columbia Utilities Commission (BCUC) issuing Notice of Initiating a Generic Cost of Capital proceeding
A-2	Letter dated March 3, 2021 – BCUC appointing the panel for review of the BCUC's Generic Cost of Capital proceeding
A-3	Letter dated March 8, 2021 – BCUC Order G-66-21 establishing a regulatory timetable and public notice
A-4	Letter dated May 21, 2021 – BCUC Order G-156-21 with Reasons for Decision and establishing the proceeding's scope and a further regulatory timetable
A-5	Letter dated June 11, 2021 – BCUC Order G-183-21 with reasons for decision and a further regulatory timetable
A-6	Letter dated July 7, 2021 – BCUC Order G-205-21 with reasons for decision and amended scope.
A-7	Letter dated July 30, 2021 – BCUC Order G-231-21 with amended regulatory timetable
A-8	Letter dated September 24, 2021 – BCUC Order G-281-21 with Reasons for Decision amending the scope and regulatory timetable
A-9	Letter dated October 6, 2021 – BCUC Order G-288-21 amending regulatory timetable
A-10	Letter dated October 27, 2021 – BCUC response to Dr. Lesser extension request
A-11	Letter dated February 28, 2022 – BCUC Information Request No. 1 to FEI and FBC

Exhibit No.	Description
A-12	Letter dated March 31, 2022 – BCUC submitting procedural conference information
A-13	Letter dated April 21, 2022 – BCUC Order G-106-22 with Reasons for Decision amending the scope and regulatory timetable
A-14	Letter dated May 16, 2022 – BCUC Information Request No. 2 to FEI and FBC
A-15	Letter dated May 16, 2022 – BCUC Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-16	Letter dated May 20, 2022 – BCUC Order G-140-22 addressing FortisBC's objections to interveners' Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-17	Letter dated May 31, 2022 – BCUC response to FortisBC's objection to interveners' revised Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-18	Letter dated June 20, 2022 – BCUC providing information for Procedural Conference No. 2
A-19	Letter dated July 8, 2022 – BCUC request for submissions regarding expert opinions and further process and scope
A-20	Letter dated August 8, 2022 – BCUC Order G-217-22 with Reasons for Decision amending the regulatory timetable and establishing the format and scope of the oral hearing
A-20-1	Letter dated August 10, 2022 – BCUC issuing Order G-217-22A with Reasons for Decision and amended regulatory timetable and Oral Hearing Scope
A-21	Letter dated August 12, 2022 – BCUC response to FortisBC request for further clarification on Oral Hearing Scope
A-22	Letter dated August 31, 2022 – BCUC Information Request No. 1 to FEI and FBC on FortisBC's Rebuttal Evidence Part 2 – Rebuttal Evidence of Concentric Energy Advisors Inc.
A-23	Letter dated October 13, 2022 – BCUC issuing Oral Hearing Information
A-24	Letter dated November 14, 2022 – BCUC Order G-327-22 with amended regulatory timetable
A-24-1	Letter dated November 14, 2022 – BCUC Order G-327-22A with amended regulatory timetable
A-25	Letter dated November 30, 2022 – BCUC Information Request No. 1 on Undertakings to FortisBC

Exhibit No.	Description
A-26	Letter dated December 9, 2022 – BCUC invitation to registered utilities and interveners to provide additional information in Final Arguments
A-27	Letter dated December 13, 2022 – BCUC request to FortisBC to file credit rating report for FBC
A-28	Letter dated January 26, 2023 – BCUC response to the CEC extension request
A-29	Letter dated January 27, 2023 – BCUC response to BCOAPO extension request
A-30	Letter dated February 17, 2023 – BCUC response to FortisBC extension request
A-31	Letter dated May 8, 2023 – BCUC request for submissions regarding the implementation of rates for utilities that use the FEI Benchmark Utility

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated March 23, 2021 – BCUC Staff submission on scope
A2-2	Letter dated June 18, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Report on Using a Benchmark Utility to Set the Cost of Capital – June 2021
A2-3	Letter dated August 4, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Regulated Utility Cost of Capital: Theory and Canadian Practice – August 2021
A2-3-1	Letter dated November 7, 2022 – BCUC Staff submission: Errata to Consultant Report in Exhibit A2-3
A2-4	Letter dated October 20, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Extension Request dated October 19, 2021
A2-5	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCOAPO Information Request No. 1 on Exhibit A2-3

Exhibit No.	Description
A2-6	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request No. 1 on Exhibit A2-3
A2-7	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to Creative Energy Information Request No. 1 on Exhibit A2-3
A2-8	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to FortisBC Inc. Information Request No. 1 on Exhibit A2-3
A2-9	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the ICG Information Request No. 1 on Exhibit A2-3
A2-10	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to MoveUP Information Request No. 1 on Exhibit A2-3
A2-11	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the RCIA Information Request No. 1 on Exhibit A2-3
A2-12	Letter dated February 28, 2022 – BCUC Staff submit excerpts from Government of Canada Department of Finance Federal Budget 2021, Annex 6: Tax Measures - Supplementary Information, International Tax Measures - Interest Deductibility Limits
A2-13	Letter dated February 28, 2022 – BCUC Staff submitting: A Review of International Approaches to Regulated Rates of Return Prepared for the Australian Energy Regulator by The Brattle Group – June 2020
A2-14	Letter dated February 28, 2022 – BCUC Staff submission: Electric ROE Authorizations Drift Lower In H1'20 As Virus Worries Continue by S&P Global Market Intelligence – August 4, 2020
A2-15	Letter dated February 28, 2022 – BCUC Staff submission: RIIO-ED2 Sector Specific Methodology Decision: Annex 3 Finance by Ofgem– March 11, 2021

Exhibit No.	Description
A2-16	Letter dated February 28, 2022 – BCUC Staff submission: Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings by Richard A. Michelfelder and Panayiotis Theodossiou, The Electricity Journal, Volume 26, Issue 9 – November 2013
A2-17	Letter dated April 12, 2022 – BCUC Staff submission: BCUC Staff Draft Regulatory Timetable and Options
A2-18	Letter dated May 16, 2022 – BCUC Staff submission: Betas and Their Regression Tendencies by Marshall E. Blume, The Journal of Finance, Volume 30, Number 3 – June 1975
A2-19	Letter dated May 19, 2022 – BCUC Staff submission: Dr. Lesser Confidentiality Declaration and Undertaking
A2-20	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCUC Information Request No. 2 to Dr. Lesser on Coyne Evidence
A2-20-1	Letter dated November 7, 2022 – BCUC Staff submission: Revised Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCUC Information Request No. 9.3.1 at the Oral Hearing
A2-21	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the RCIA Information Request No. 2
A2-22	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to ICG Information Request No. 2
A2-23	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request No. 2
A2-23-1	Letter dated June 21, 2022 – BCUC Staff submission: Consultant amended response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request 2 Question 23.1
A2-24	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to BCOAPO Information Request No 2
A2-25	Letter dated June 14, 2022 – BCUC Staff submission: Response attachment to BCUC Information Request No. 1.3

Exhibit No.	Description
A2-26	Letter dated June 14, 2022 – BCUC Staff submission: Panhandle Eastern Pipe Line Company, LP – Initial Decision – Public Version – March 26, 2021
A2-27	Letter dated June 14, 2022 – BCUC Staff submission: New Regulatory Finance, pp. 190, 303 – 307, 324, by Roger A. Morin, PhD
A2-28	Letter dated June 14, 2022 – BCUC Staff submission: Financial Flexibility, Corporate Investment and Performance: Evidence from Financial Crises – By Ozgur Arslan-Ayaydin, Chris Florackis, Aydin Ozkan
A2-29	Letter dated June 14, 2022 – BCUC Staff submission: On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital – The Journal of Finance – Volume XXXV, No. 2, pp. 369 – 383, May 1980 – By Robert Litzenerger, Krishna Ramaswamy, and Howard Sosin
A2-30	Letter dated June 14, 2022 – BCUC Staff submission: Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings – The Electricity Journal – Volume 29, Issue 9, November 2013 – By Richard A. Michelfelder and Panayiotis Theodossiou
A2-31	Letter dated July 14, 2022 – BCUC Staff submission regarding expert opinions and further process and scope
A2-32	Letter dated October 28, 2022 – BCUC Staff filing Continental Economics, Inc. Dr. Jonathan Lesser CV
A2-33	Letter dated November 7, 2022 – BCUC Staff submission: Witness Aid Part 1 Diverging Opinions of Experts at the Oral Hearing
A2-34	Letter dated November 7, 2022 – BCUC Staff submission: ROE Results Based on Multi-Stage vs Single-Stage DCF to Calculate Forward Looking MRP Experts at the Oral Hearing
A2-35	Letter dated November 7, 2022 – BCUC Staff submission: Return on Equity Calculations Using Different Methodologies and Assumptions (Summary of Exhibit B1-25) at the Oral Hearing
A2-35-1	Letter dated November 9, 2022 – BCUC Staff submission: Amendment to Exhibit A2-35 at the Oral Hearing

Exhibit No.	Description
A2-36	Letter dated November 9, 2022 – BCUC Staff submission: Part 2 of the BCUC Witness Aid at the Oral Hearing
A2-37	Letter dated November 9, 2022 – BCUC Staff submission: Section of FortisBC website relating to Sustainability at the Oral Hearing
A2-38	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC Application for Approval of a Multi-Year Rate Plan for 2020 through 2024 at the Oral Hearing
A2-39	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC 2021 Green Bond Impact Report at the Oral Hearing
A2-40	Letter dated November 9, 2022 – BCUC Staff submission: Canadian 2022 Federal Budget page 106 at the Oral Hearing
A2-41	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC Application for Approval of Large Commercial Interruptible Rate page 3 at the Oral Hearing

APPLICANT DOCUMENTS

B1-1	**FORTISBC ENERGY INC. (FEI) –** Letter dated March 16, 2021 submitting registration by Diane Roy
B1-2	Letter dated March 29, 2021 – FEI submission on Preliminary Scope Document
B1-3	Letter dated June 4, 2021 – FEI submission on proceeding Scope and Deferral Account
B1-4	Letter dated July 21, 2021 – FEI submission on Use of a Benchmark Utility
B1-5	Letter dated August 13, 2021 – FEI submission on cost eligibility of PACA
B1-6	Letter dated September 30, 2021 – FEI submitting request for amendment to Regulatory Timetable
B1-7	Letter dated October 15, 2021 – FEI submitting Information Request No. 1 on Exhibit A2-3
B1-8	Letter dated January 31, 2022 – FEI and FBC submitting evidence for Stage 1 of proceeding

Exhibit No.	Description
B1-8-1	Letter dated January 31, 2022 – FEI and FBC submitting evidence for Stage 1 of proceeding – Appendices
B1-8-1-1	Letter dated October 20, 2022 – FortisBC submitting errata to Appendix A – FEI Business Risk Assessment
B1-8-1-2	Letter dated October 20, 2022 – FortisBC submitting September Update to Concentric Financial Models
B1-9	Letter dated April 6, 2022 – FEI and FBC submitting responses to BCUC Information Request No. 1 on FortisBC Evidence
B1-9-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting responses to BCUC Information Request No. 1 on FortisBC Evidence Confidential Attachments
B1-10	Letter dated April 6, 2022 – FEI and FBC submitting responses to BCOAPO Information Request No. 1 on FortisBC Evidence
B1-10-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting responses to BCOAPO Information Request No. 1 on FortisBC Evidence Confidential Attachments
B1-11	Letter dated April 6, 2022 – FEI and FBC submitting responses to CEC Information Request No. 1 on FortisBC Evidence
B1-11-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting confidential response to CEC Information Request No. 1 on FortisBC Evidence and Confidential Attachments
B1-12	Letter dated April 6, 2022 – FEI and FBC submitting responses to ICG Information Request No. 1 on FortisBC Evidence
B1-12-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting confidential response to ICG Information Request No. 1 Question 5.1 on FortisBC Evidence
B1-13	Letter dated April 6, 2022 – FEI and FBC submitting responses to RCIA Information Request No. 1 on FortisBC Evidence
B1-14	Letter dated May 19, 2022 – FEI and FBC submitting Information Requests Out of Scope

Exhibit No.	Description
B1-15	Letter dated May 26, 2022 – FEI and FBC further submission on Information Requests out of scope
B1-16	Letter dated May 30, 2022 – FEI and FBC submitting response to ICG Information Request No. 2 regarding Dr. Lesser
B1-17	Letter dated June 14, 2022 – FortisBC submitting response to RCIA Information Request No. 2 on FortisBC Evidence
B1-18	Letter dated June 14, 2022 – FortisBC submitting response to CEC Information Request No. 2 on FortisBC Evidence
B1-19	Letter dated June 14, 2022 – FortisBC submitting response to BCOAPO Information Request No. 2 on FortisBC Evidence
B1-19-1	**CONFIDENTIAL** - Letter dated June 14, 2022 – FortisBC submitting confidential responses to BCOAPO Information Request No. 2 on FortisBC Evidence
B1-20	Letter dated June 14, 2022 – FortisBC submitting response to BCUC Information Request No. 2 on FortisBC Evidence
B1-21	Letter dated June 28, 2022 – FortisBC submitting Rebuttal Evidence
B1-22	Letter dated July 14, 2022 – FortisBC submission regarding expert opinions and further process and scope
B1-23	Letter dated July 20, 2022 – FortisBC reply submission regarding expert opinions and further process and scope
B1-24	Letter dated August 11, 2022 – FortisBC request further clarification on Oral Hearing Scope
B1-25	Letter dated October 20, 2022 – FortisBC submitting responses to BCUC Information Request No. 1 on Rebuttal Evidence
B1-25-1	Letter dated November 4, 2022 – FortisBC submitting errata to responses to BCUC Information Request No. 1 Question 6.2 on Rebuttal Evidence
B1-26	Letter dated October 20, 2022 – FortisBC submitting responses to BCOAPO Information Request No. 1 on Rebuttal Evidence

Exhibit No.	Description
B1-27	Letter dated October 20, 2022 – FortisBC submitting responses to CEC Information Request No. 1 on Rebuttal Evidence
B1-28	Letter dated October 20, 2022 – FortisBC submitting responses to RCIA Information Request No. 1 on Rebuttal Evidence
B1-29	Letter dated October 31, 2022 – FortisBC submitting Witness Panel, Direct Testimony and Notice of Cross-Examination
B1-30	Letter dated November 3, 2022 – FortisBC submitting Opening Statements
B1-31	Letter dated November 7, 2022 – FortisBC submitting Concentric Energy Advisor Multi-Stage DCF and CAPM Results at the Oral Hearing
B1-32	Letter dated November 7, 2022 – FortisBC submitting U.S. Court of Appeals Emera Maine No. 15-1118 at the Oral Hearing
B1-33	Letter dated November 7, 2022 – FortisBC submitting U.S. Court of Appeals MISO ROE Opinion No. 16-1325 at the Oral Hearing
B1-34	Letter dated November 7, 2022 – FortisBC submitting PPL Corporation sell of U.K. Utility Business at the Oral Hearing
B1-35	Letter dated November 7, 2022 – FortisBC submitting PNM Resources Investor News Releases at the Oral Hearing
B1-36	Letter dated November 8, 2022 – FortisBC submitting US Securities and Exchange Commission Quarterly Report at the Oral Hearing
B1-37	Letter dated November 8, 2022 – FortisBC submitting Consolidated Edison Quarterly Earnings Presentation at the Oral Hearing
B1-38	Letter dated November 8, 2022 – FortisBC submitting Exelon Fall 2022 Investor Meetings at the Oral Hearing
B1-39	Letter dated November 8, 2022 – FortisBC submitting US Federal Energy Regulatory Commission Hearing at the Oral Hearing
B1-40	Letter dated November 8, 2022 – FortisBC submitting Testimony of Dr Lesser before the Arkansas Public Service Commission at the Oral Hearing

Exhibit No.	Description
B1-41	Letter dated November 8, 2022 – FortisBC submitting Testimony of Dr Lesser before the Illinois Commerce Commission at the Oral Hearing
B1-42	Letter dated November 8, 2022 – FortisBC submitting Bank of Canada Interest Rates at the Oral Hearing
B1-43	Letter dated November 8, 2022 – FortisBC submitting S&P TSX Utilities Index Dividend Yield at the Oral Hearing
B1-44	Letter dated November 8, 2022 – FortisBC submitting excerpt Capital Pricing Model from Exhibit B1-8-1-1 at the Oral Hearing
B1-45	Letter dated November 8, 2022 – FortisBC submitting 169 FERC Docket Nos. EL14-12-003 and EL15-45-000 at the Oral Hearing
B1-46	Letter dated November 8, 2022 – FortisBC submitting Wilshire 5000 Total Market Full Cap Index/Gross Domestic Product at the Oral Hearing
B1-47	Letter dated November 8, 2022 – FortisBC submitting Stock Market Capitalization to GDP for Canada at the Oral Hearing
B1-48	Letter dated November 8, 2022 – FortisBC submitting charts showing 10-year Actual vs Consensus Forecasts in Canada and the US at the Oral Hearing
B1-49	Letter dated November 9, 2022 – FortisBC submitting FEI 2022 Long Term Gas Resource Plan excerpt at the Oral Hearing
B1-50	Letter dated November 23, 2022 – FortisBC submitting response to Undertakings
B1-50-1	Letter dated December 12, 2022 – FortisBC providing Moody Credit Rating Report regarding response to Undertaking No. 3
B1-51	Letter dated December 9, 2022 – FortisBC submitting response to BCUC Information Request No. 1 Undertakings
B1-52	Letter dated December 9, 2022 – FortisBC submitting response to CEC Information Request No. 1 Undertakings
B1-53	Letter dated December 9, 2022 – FortisBC submitting response to RCIA Information Request No. 1 Undertakings

Exhibit No.	Description
B1-54	Letter dated February 17, 2023 – FortisBC submitting extension request to file Reply Argument
B2-1	**FORTISBC INC. (FBC) –** Letter dated March 16, 2021 submitting registration by Diane Roy
B2-2	Letter dated March 29, 2021 – FBC submission on Preliminary Scope Document
B2-3	Letter dated June 4, 2021 – FBC submission on proceeding Scope and Deferral Account
B2-4	Letter dated July 21, 2021 – FBC submission on Use of a Benchmark Utility
B2-5	Letter dated August 13, 2021 – FBC submission on cost eligibility of PACA
B2-6	Letter dated September 30, 2021 – FBC submitting request for amendment to Regulatory Timetable
B2-7	Letter dated October 15, 2021 – FBC submitting Information Request No. 1 on Exhibit A2-3
B2-8	Letter dated December 14, 2022 – FBC submitting Moody Credit Rating Report regarding response to Undertaking
B3-1	**FORTISBC ALTERNATIVE ENERGY SERVICE INC. (FAES) –** Letter dated March 16, 2021 submitting registration by Grant Bierlmeier
B3-2	Letter dated March 31, 2021 – FAES submission on Preliminary Scope Document
B3-3	Letter dated June 4, 2021 – FAES submission on proceeding Scope and Deferral Account
B3-4	Letter dated July 21, 2021 – FAES submission on Use of a Benchmark Utility
B4-1	**Nelson Hydro** – Letter dated March 19, 2021 submitting registration by Gabriel Bouvet-Boisclair
B4-2	Letter dated March 30, 2021 – Nelson Hydro submission on Preliminary Scope Document
B4-3	Letter dated July 21, 2021 – Nelson Hydro submission on Use of a Benchmark Utility
B4-4	Letter dated August 13, 2021 – Nelson Hydro submission on cost eligibility of PACA

Exhibit No.	Description
B5-1	**Kyuquot Power Ltd. (KPL)** – Letter dated March 22, 2021 submitting registration by Taya DeAngelis
B5-2	Letter dated March 31, 2021 – KPL submission on Preliminary Scope Document
B6-1	**Corx Multi-Utility Services Inc. (Corix)** – Letter dated March 22, 2021 submitting registration by Errol South
B6-2	Letter dated March 31, 2021 – Corix submission on Preliminary Scope Document
B6-3	Letter dated June 4, 2021 – Corix submission on proceeding Scope and Deferral Account
B6-4	Letter dated July 21, 2021 – Corix Brattle Report submission on Use of a Benchmark Utility
B6-5	Letter dated July 21, 2021 – Corix submission on Use of a Benchmark Utility
B6-6	Letter dated August 12, 2021 – Corix submission on cost eligibility of PACA
B7-1	**Creative Energy Vancouver platforms Inc. (Creative Energy)** – Letter dated March 22, 2021 submitting registration by Rob Gorter
B7-2	Letter dated March 31, 2021 – Creative Energy submission on Preliminary Scope Document
B7-3	Letter dated June 4, 2021 – Creative Energy submission on proceeding Scope and Deferral Account
B7-4	Letter dated July 21, 2021 – Creative Energy submission on Use of a Benchmark Utility
B7-5	Letter dated August 13, 2021 – Creative Energy submission on cost eligibility of PACA
B7-6	Letter dated October 15, 2021 – Creative Energy submitting Information Request No. 1 on Exhibit A2-3
B8-1	**River District Energy (RDE)** – Letter dated March 18, 2021 submitting registration by Ross Hanson
B8-2	Letter dated March 31, 2021 – RDE submission on Preliminary Scope Document

Exhibit No.	Description
B9-1	**Pacific Northern Gas Ltd. (PNG) and Pacific Northern Gas (N.E.) Ltd. (PNGNE) (collectively PNG)** – Letter dated March 24, 2021 submitting registration by Gordon Doyle
B9-2	Letter dated March 31, 2021 – PNG submission on Preliminary Scope Document
B9-3	Letter dated June 4, 2021 – PNG submission on proceeding Scope and Deferral Account
B9-4	Letter dated July 21, 2021 – PNG submitting notice of Additional Contact
B9-5	Letter dated July 21, 2021 – PNG Brattle Report submission on Use of a Benchmark Utility
B9-6	Letter dated July 21, 2021 – PNG submission on Use of a Benchmark Utility
B9-7	Letter dated August 13, 2021 – PNG submission on cost eligibility of PACA

INTERVENER DOCUMENTS

C1-1	**RESIDENTIAL CONSUMER INTERVENER ASSOCIATION (RCIA) –** Letter dated March 12, 2021 submitting request to intervene by Fredrik Ambrosson
C1-2	Letter dated March 31, 2021 – RCIA submission on Preliminary Scope Document
C1-3	Letter dated June 4, 2021 – RCIA submission on proceeding Scope and Deferral Account
C1-4	Letter dated July 21, 2021 – RCIA submission on Use of a Benchmark Utility
C1-5	Letter dated August 13, 2021 – RCIA submission on cost eligibility of PACA
C1-6	Letter dated October 12, 2021 – RCIA submitting Information Request No. 1 on Exhibit A2-3
C1-7	Letter dated March 7, 2022 – RCIA submitting Information Request No. 1 on FortisBC Evidence
C1-8	Letter dated May 16, 2022 – RCIA submitting Information Requests No. 2 to FortisBC and Dr. Lesser regarding Mr. Coyne's evidence

Exhibit No.	Description
C1-8-1	Letter dated May 25, 2022 – RCIA submitting revised Information Requests No. 2 to FortisBC and Dr. Lesser regarding Mr. Coyne's evidence
C1-9	Letter dated July 14, 2022 – RCIA submission regarding expert opinions and further process and scope
C1-10	Letter dated September 12, 2022 – RCIA submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C1-11	Letter dated November 8, 2022 – RCIA submitting Witness Aid Part 1 at the Oral Hearing
C1-12	Letter dated November 8, 2022 – RCIA submitting Witness Aid Part 2 at the Oral Hearing
C1-13	Letter dated November 29, 2022 – RCIA submitting Information Request No. 1 on FortisBC response to Undertakings
C2-1	**Movement of United Professionals (MoveUP)** – Letter dated March 14, 2021 submitting request to intervene by Jim Quail
C2-2	Letter dated March 31, 2021 – MoveUP submission on Preliminary Scope Document
C2-3	Letter dated July 16, 2021 – MoveUP submission on Order G-183-21 Appendix A
C2-4	Letter dated August 13, 2021 – MoveUP submission on cost eligibility of PACA
C2-5	Letter dated October 12, 2021 – MoveUP submitting Information Request No. 1 on Exhibit A2-3
C3-1	**BORALEX OCEAN FALLS LIMITED PARTNERSHIP (BORALEX LP) –** Letter dated March 22, 2021 submitting request to intervene by Maxime Tremblay
C4-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC) –** Letter dated March 22, 2021 submitting request to intervene by Matthew Keen
C4-2	Letter dated April 1, 2021 – AMPC submission on Preliminary Scope Document
C5-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** – Letter dated March 22, 2021 submitting request to intervene by Robert Hobbs
C5-2	Letter dated March 31, 2021 – ICG submission on Preliminary Scope Document
C5-3	Letter dated June 4, 2021 – ICG submission on proceeding Scope and Deferral Account

Exhibit No.	Description
C5-4	Letter dated July 21, 2021 – ICG submission on Use of a Benchmark Utility
C5-5	Letter dated August 13, 2021 – ICG submission on cost eligibility of PACA
C5-6	Letter dated October 15, 2021 – ICG submitting Information Request No. 1 on Exhibit A2-3
C5-7	Letter dated March 7, 2022 – ICG submitting Information Request No. 1 on FortisBC Evidence
C5-8	Letter dated May 16, 2022 – ICG submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C5-8-1	Letter dated May 25, 2022 – ICG submitting revised Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C5-9	Letter dated May 27, 2022 – ICG submission regarding revised Information Request No. 2
C5-10	Letter dated July 14, 2022 – ICG submission regarding expert opinions and further process and scope
C5-11	Letter dated November 7, 2022 – ICG submitting Confidential Declaration and Undertaking
C6-1	**Commercial Energy Consumers Association of British Columbia (CEC)** – Letter dated March 22, 2021 submitting request to intervene by Christopher Weafer
C6-2	Letter dated March 31, 2021 – CEC submission on Preliminary Scope Document
C6-3	Letter dated June 4, 2021 – CEC submission on proceeding Scope and Deferral Account
C6-4	Letter dated July 21, 2021 – CEC submission on Use of a Benchmark Utility
C6-5	Letter dated August 13, 2021 – CEC submission on cost eligibility of PACA
C6-6	Letter dated October 8, 2021, CEC submitting extension request to file Information Requests on Exhibit A2-3
C6-7	Letter dated October 15, 2021 – CEC submitting Information Request No. 1 on Exhibit A2-3
C6-8	Letter dated March 7, 2022 – CEC submitting Information Request No. 1 on FortisBC Evidence

Exhibit No.	Description
C6-9	Letter dated May 16, 2022 – CEC submitting Information Request No. 2 on FortisBC Evidence
C6-10	Letter dated May 16, 2022 – CEC submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C6-11	Letter dated July 14, 2022 – CEC submission regarding expert opinions and further process and scope
C6-12	Letter dated September 12, 2022 – CEC submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C6-13	Letter dated November 8, 2022 – CEC submitting Fortis Inc. Releases Second Quarter 2022 Results and 2022 Sustainability Report at the Oral Hearing
C6-14	Letter dated November 9, 2022 – CEC submitting Fortis Inc. Investor Presentation Q4 2022 at the Oral Hearing
C6-15	Letter dated November 9, 2022 – CEC submitting Witness Aid for Excerpts from Long Term Gas Resource Plan at the Oral Hearing
C6-16	Letter dated November 30, 2022 – CEC submitting Information Request No. 1 on Undertakings
C6-17	Letter dated January 24, 2023 – CEC submitting extension request to file Final Argument
C7-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, TENANTS RESOURCE AND ADVISORY CENTRE, AND TOGETHER AGAINST POVERTY SOCIETY (BCOAPO et al.) –** Letter dated March 22, 2021 submitting request to intervene by Leigha Worth and Irina Mis
C7-2	Letter dated March 31, 2021 – BCOAPO submission on Preliminary Scope Document
C7-3	Letter dated July 21, 2021 – BCOAPO submission on Use of a Benchmark Utility
C7-4	Letter dated August 13, 2021 – BCOAPO submission on cost eligibility of PACA
C7-5	Letter dated October 15, 2021 – BCOAPO submitting Information Request No. 1 on Exhibit A2-3
C7-6	Letter dated March 7, 2022 – BCOAPO submitting Information Request No. 1 on FortisBC Evidence

Exhibit No.	Description
C7-7	Letter dated May 16, 2022 – BCOAPO submitting Information Request No. 2 to FortisBC
C7-8	Letter dated May 16, 2022 – BCOAPO submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C7-9	Letter dated July 14, 2022 – BCOAPO submission regarding expert opinions and further process and scope
C7-10	Letter dated September 12, 2022 – BCOAPO submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C7-11	Letter dated January 26, 2022 – BCOAPO submitting extension request to file Final Argument
C8-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO) –** Letter dated March 22, 2021 submitting request to intervene by Fred James
C8-2	Letter dated June 4, 2021 – BC Hydro submission on proceeding Scope and Deferral Account
C9-1	**CLEAN ENERGY ASSOCIATION OF BC (CEABC) –** Letter dated March 22, 2021 submitting request to intervene by Laureen Whyte
C9-2	Letter dated June 1, 2021 – CEABC submission on proceeding Scope and Deferral Account
C9-3	Letter dated April 12, 2021 – CEABC withdrawing intervener status

INTERESTED PARTY DOCUMENTS

D-1	**ONNI GROUP (ONNI)** - Submission dated March 23, 2021 request for Interested Party Status by Michelle McLarty
D-2	**CHOY, MAURICE (CHOY)** - Submission dated July 13, 2021 request for Interested Party Status
D-3	**JARVI, MARK (JARVI)** – Submission dated July 28, 2021 request for Interested Party Status

LETTERS OF COMMENT

E-1	**DE LA GARZA, S. (DELAGARZA)** – Letter of Comment dated February 15, 2022

REFERENCE: **Application, PDF page 514**

ISSUE: ROE

QUOTE: AEY has recently filed its GRA and has applied for a risk premium of 75 basis points, versus the 25 basis points AEY risk premium last approved by the YUB. YEC's risk has historically been consistently assessed to be higher than AEY's – and there is no evidence of any change to their relative risk profiles that would suggest this would not be the case today. Accordingly, YEC's risk premium will need to continue to be higher for the test years than the final risk premium approved for AEY.

QUESTION:

a) Please confirm that, subject to the BCUC GCOC finding for the benchmark utility, YEC submits that a fair return for it is the ROE for that BCUC benchmark utility plus 45 basis points risk premium (before OIC 1995/90) as long as the risk premium for YEC is higher than the risk premium awarded to AEY in its 2023-24 GRA proceeding currently before the Board.

b) Please confirm that when YEC refers to the BCUC GCOC benchmark utility, YEC is referring to Fortis Energy Inc. If not confirmed, please explain.

ANSWER:

(a)

Confirmed, based on the evidence available prior to the recent BCUC Stage 1 GCOC decision (Order G-236-23) referenced and provided in response to YUB-YEC-1-84. As reviewed in response to "b" below, this recent BCUC decision leaves unresolved any updated BCUC benchmark and related risk premiums for other electric utilities in BC.

Prior to the oral hearing on YEC's Application, the Board will review this same Stage 1 BCUC decision and related ROE issues in the oral hearing on the AEY GRA application. Regardless of the ROE determination approved by the Board with regard to AEY, YEC submits that a fair return to YEC (before applying the 0.5% adjustment required by section

2(2) of OIC 1995/90) must provide for a higher risk premium for YEC than that to be approved for AEY in its 2023-24 GRA proceeding currently before the Board.

(b)

The BCUC benchmark utility referenced by YEC prior to the recent BCUC GCOC proceeding was the gas utility FortisBC Energy Inc. (FEI). However, the recent BCUC GCOC decision (Order G-236-23) approving an ROE of 9.65% for both FEI and the electric utility FortisBC Inc. (FBC) has deferred BCUC determinations on benchmark utility related issues to the BCUC GCOC Stage 2 proceeding that starts in November 2023 and is expected to be concluded in 2024.

The BCUC Stage 2 GCOC is expected to address the following questions:

- Whether FEI should continue as the appropriate default benchmark utility for some or all other utilities in BC;
- Whether FBC is a more appropriate benchmark;
- Whether neither FEI nor FBC should serve as the benchmark; and
- Whether each utility's allowed ROE and deemed capital structure should be determined individually.

It is relevant to note that the recent BCUC decision changed the relationship between ROEs for FEI and FBC. Prior to Order G-236-23, FBC's approved ROE of 9.15% was based on the FEI benchmark ROE of 8.75% plus a risk premium of 40 basis points – with FBC deemed equity approved at 40% as compared with FEI deemed equity approved at 38.5%. In contrast, Order G-236-23 approved the same ROE (9.65%) for both FBC and FEI, with approved deemed equity of 41% for FBC now being lower than FEI's approved deemed equity of 45%.

REFERENCE: **Application, PDF page 516**

ISSUE: ROE

QUOTE: In summary, the information in Tables 8.1 and 8.2 reflects the continuing applicability of setting the YEC risk premium relative to the BCUC ROE benchmark at 45 basis points based on a fair analysis of risks and comparative utilities review confirming that YEC's overall risk is still greater than FortisBC (Electric) as well as AEY.

QUESTION:

a) Did the information referred to in the summary or similar information — for example, a previous year — exist at the time of YEC's 2021 GRA? Please explain.

ANSWER:

(a)

Yes. The information referred to in Tables 8.1 and 8.2 existed for 2019 and was documented in YEC's 2021 GRA filing. As noted, similar information on comparative utility size of operations, financial structure, and nature of business (e.g., reliance on own generation, isolated grid, significance of industrial customer loads) was also documented for YEC's 2017/18 GRA.

REFERENCE: **Application, PDF pages 110 and 516**

ISSUE: ROE

QUOTE: Application, PDF page 516:

In 2022, FortisBC 1 (Electric) operations had approximately 148,861 customers, approximately $1,583 million in rate base, and a 60/40 debt/equity ratio. This is compared to YEC's 2,341 customer base and $303 million rate base. While Yukon Energy's financial structure is the same as FortisBC (Electric), the customer count was at approximately 1.6% of FortisBC (Electric); and its rate base was approximately 20% that of FortisBC (Electric). This is similar to the comparison provided in 2021.

On the other hand, information relating to AEY indicates that it has approximately 20,308 customers and rate base of $115.0 million and a 60/40 debt/equity ratio as at 2022. This indicates that YEC has just about 11% of AEY's customer base while they maintain same capital structure.

Application, PDF page 110:

AVAILABLE: To all electric service throughout the Yukon Territory.

…

RATE: Rider J at 39.64% applicable to the base rates of the following rate classes to recover of a portion of the 2023/24 revenue shortfall. All ATCO Electric Yukon recoveries from this rider to flow through to the Yukon Energy Corporation.

QUESTION:

a) As YEC collects a portion of its rates from customers across Yukon, as shown for Rider J, does this mitigate some of the risks of YEC's 2,341-customer base?

b) With wholesales to AEY being YEC's largest customer, does this mean that, for comparison purposes, YEC's customer base should be amended to reflect AEY customers on the YIS? Please explain.

ANSWER:

(a) and (b)

The fact that YEC collects a portion of its rates from customers across Yukon, indirectly via YECL/AEY, does not mitigate the risks of YEC's 2,341-customer base. Similarly, the fact that wholesales to AEY is YEC's largest customer does not mean that, for comparison purposes, YEC's customer base should be amended to reflect AEY's customers on the YIS.

YEC's ability to collect revenues directly from AEY customers, as well as AEY's ability to collect revenues directly from YEC customers, including industrial customers, depend on each utility's ability to rely on rate riders. (In contrast, if customer base rates were instead to be updated through a Phase 2 proceeding, that would once again restrict each utility's revenues to its customers.)

To the extent that YEC depends on wholesale revenues from AEY, YEC is exposed to the revenue risks associated with relying on wholesale rates that are currently determined mainly on a single energy rate basis.

Further, despite YEC's ability to rely on rate riders and wholesales to AEY, YEC's distribution services and infrastructure remain very small compared with AEY's distribution services and infrastructure – and, compared with AEY, YEC assets and costs are focused on bulk supply activities (generation and transmission).

For the purpose of business risk assessments (related to ROE determinations), YEC size comparisons with other utilities in all GRAs to date have focused on the actual customers and sales of YEC vs. YECL/AEY (as opposed to any other approach that may be suggested by this information request). There is no apparent or reasonable new basis for changing this comparison approach for business risk assessments in the current YEC GRA.

REFERENCE: **Board Order 2023-24, PDF page 2**

ISSUE: Hyperlinks

QUOTE: In respect of the hyperlinks contained in the Application and in some of its IR Responses, AEY is to file by October 24, 2023, a separate document referencing the location (PDF page number) of the hyperlink in the Application or the IR number and PDF page number in the IR Responses.

PREAMBLE: The Board does not accept documents containing hyperlinks. YEC's Application contains hyperlinks.

QUESTION:

a) For all references to hyperlinks in the Application, please file separate PDF documents of each hyperlinked document. In those PDF documents, include references to the PDF page number of the Application where the hyperlink reference was originally made.

ANSWER:

(a)

Please see the table that follows which provides the PDF page reference and location of each hyperlink in Yukon Energy's GRA application. Attachment 1 provides the PDF documents referenced in this table. The table and Attachment 1 do not reference or provide documents where a hyperlink was provided as a reference in a third party documents included in Yukon Energy's GRA Application.

2023-2024 YEC GRA Application- Hyperlink Listing				
Line No	**Hyperlink**	**PDF Page Number**	**Document**	**Document Reference**
1	Yukon government hires contractor to ensure environmental protection at the Minto Mine | Government of Yukon	28, 31	Minto Mine Environmental Protection	Reference 1
2	Secondary_Sales_Rate_-_April_1__2023.pdf (yukonutilitiesboard.yk.ca)	100	Quarterly Adjustment to Secondary Sales	Reference 2
3	Northland Utilities (Yellowknife) Limited	114	Bill Calculator- NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED	Reference 3
4	Residential Electrical Rates | Northwest Territories Power Corporation (ntpc.com)	114	Monthly Bills for NWT Thermal Zone	Reference 4
5	Customer Rates | Qulliq Energy Corporation (qec.nu.ca)	114	Iqaluit Customer Rates	Reference 5
6	Bill calculator | Ontario Energy Board (oeb.ca)	114	Ontario Energy Board Bill Calculator	Reference 6
7	Comparison of Electricity Prices in Major North American Cities 2022 (hydroquebec.com)	114	Comparison of Electricity Prices in Major North American Cities	Reference 7
8	Aggregated Generic Load Curve for	242	Aggregated Generic Load Curve for Residential Electric Water Heaters	Reference 8

2023-2024 YEC GRA Application- Hyperlink Listing				
Line No	**Hyperlink**	**PDF Page Number**	**Document**	**Document Reference**
	Residential Electric Water Heaters (uky.edu)			
9	End Use Load Shapes (epri.com)	242	End Use Load Shapes	Reference 9
10	U.S. Energy Information Administration - EIA - Independent Statistics and Analysis	242	Today in Energy	Reference 10
11	Residential End-use Electricity Demand: Implications for Real Time Pricing in Sweden on JSTOR	242	Residential End-use Electricity Demand: Implications for Real Time Pricing in Sweden	Reference 11
12	FortisBC (Electric)_FS with Notes_Q4_2022_C1	517, 518	Fortis BC Consolidated Financial Statements December 2022	Reference 12
13	FBC Annual Review for 2023 Rates Application (fortisbc.com)	517, 518	Fortis BC- Annual Review for 2023 Rates	Reference 13
14	FBC AR 2019 Rates - BCUC IR1 Response (windows.net)	517	Fortis BC- Annual Review for 2019 Rates	Reference 14

1

Yukon government hires contractor to ensure environmental protection at the Minto Mine

Published 13/05/2023

The Government of Yukon has hired a contractor to ensure environmental protection is maintained at the Minto Mine.

The mine operator, Minto Metals Corporation, has indicated that it is not able to continue operations at the site.

JDS Mining has been immediately mobilized to the Minto Mine site under contract to the Government of Yukon. The company is familiar with the operation of the mine and has experience in mine site care and maintenance elsewhere in the Yukon.

The contractor will continue with water treatment and management of water stored on the site to ensure the environment remains protected.

The Government of Yukon holds financial security for the site and intends to use this funding to cover the costs of the work.

> We are working closely with the contractor and the Selkirk First Nation to ensure that the environment remains protected at all times. Swift action will support the continuity of environmental protection at the site. We support responsible mining across the territory. I recognize that this is a challenging time for Minto employees, subcontractors and the community.
>
> **Minister of Energy, Mines and Resources John Streicker**

Quick facts

- The Yukon government will pay JDS Mining to provide temporary care and maintenance of the mine site until the end of June, with the option to extend as needed.

Media contact

Jordan Owens
Cabinet Communications
867-332-0615
Jordan.owens@yukon.ca

Jesse Devost
Communications, Energy, Mines and Resources
867-332-1177
jesse.devost@yukon.ca

News release #:

23-167

Was this page helpful? *

#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

February 27, 2023

Yukon Utilities Board
Box 31728
Whitehorse, YT
Y1A 6L3

Attention: Mr. Richard Buchan, Chair

Re: Quarterly Adjustment to Secondary Sales Rates as of April 1, 2023

Pursuant to Rate Schedule 32 Secondary Energy (as approved in Board Order 2005-12), the following sets out the quarterly adjustment to the Secondary Energy rate effective for consumption on or after April 1, 2023.

April 1, 2023 Rate Determination

As outlined in Rate Schedule 32, the Secondary Energy rate for April 1, 2023 is based on the Yukon Bureau of Statistics biweekly price for Furnace Oil in Whitehorse for the three reporting periods prior to the 20th day of February 2023. The lowest value of the three (net of GST) is the "Oil Price Index" for rate determination. The three reported values (including GST) are as follows:

January 11, 2023 = $2.111 /litre
January 25, 2023 = $2.086 /litre
February 8, 2023 = $2.006 /litre

Consequently, the Oil Price Index for the April 1, 2023 rate is 191.05 cents/litre (the February 8, 2023 value of 200.6 cents/litre less the GST included in that value). An Oil Price Index of 191.05 cents/litre equals a Secondary Energy rate of 13.3 cents/kWh (compared to the January 1, 2023 rate of 12.9 cents/kWh) and results in a Rate Schedule 43 Wholesale Secondary energy rate of 12.2 cents/kWh (compared to the January 1, 2023 rate of 11.8 cents/kWh).

#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

	January 1, 2023 Rate	Change	April 1, 2023 Rate
Secondary Energy	12.9 cents/kWh	0.4 cents/kWh	13.3 cents/kWh
Wholesale Secondary Energy	11.8 cents/kWh	0.4 cents/kWh	12.2 cents/kWh

Notification of Interested Parties

Rate Schedule 32 provides that the Secondary Energy Charge is to be filed with the Board at least 30 days in advance of the Rate Period. As with past notifications regarding the rate change, Yukon Energy is providing notice to ATCO Electric Yukon (AEY) at the same time as this notice is sent to the Board. Secondary Sales Retail customers will be notified by a billing advisory message on their monthly bill when their retail account is actively in service.

Current Status of Secondary Sales

Yukon Energy expects secondary sales will be available starting in May/June.

If you have any questions regarding the above, please call.

Yours truly,

Jason Epp, CPA, CA
Director of Finance

CUSTOMER BILLING & RATES

BILL CALCULATOR – NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED

CUSTOMER BILLING & RATES → BILL CALCULATOR

This calculator is for Northland Utilities (Yellowknife) Limited customers in Yellowknife or N'Dilo. If you're not sure which company provides your services, please check your bill.

NORTHLAND UTILITIES YELLOWKNIFE

Effective Jun 1, 2023

Service Type

- (●) Residential
- ( ) General Service

Area of Residence

Yellowknife

Rate Schedule	Residential - 1880
Consumption	kWh
Customer Charge (per month)	$18.00
Energy Charge ($/kWh)	
Subtotal	
Rider R Rate Adjustment Rider	
Purchase Power Cost Adjustment Rider F ($/kWh)	
Total Riders	
Total With Riders	

Franchise Tax

Current Billing before GST Subtotal

Federal GST

Total

Northland Utilities (Yellowknife) Limited
481 Range Lake Road
Yellowknife, NT
X1A 3R9

Northland Utilities (NWT) Limited
1-66 Woodland Drive
Hay River, NT
X0E 1G1

Phone (Yellowknife) : 1-867-873-4865
Phone (NWT) : 1-867-874-6879 or 1-800-264-5313

CURRENT OUTAGES
PLANNED OUTAGES
ACCOUNT FORMS
BILL CALCULATOR
SUBMIT YOUR METER READING
FREQUENTLY ASKED QUESTIONS

PRIVACY TERMS OF USE

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RESIDENTIAL ELECTRICAL RATES

EFFECTIVE APRIL 1, 2023

Thermal Zone Communities:

Aklavik, Colville Lake, Deline, Fort Good Hope, Fort Liard, Fort McPherson, Fort Simpson, Gameti, Inuvik, Jean Marie River, Lutsel k'e, Nahanni Butte, Paulatuk, Sachs Harbour, Tsiigehtchic, Tuktoyaktuk, Tulita, Ulukhaktok, Whati, Wrigley.

	Your cost	*Actual cost*
Service fee	$18	**$18**
Up to 600 kWh		

- **Energy charge**	31.08 cents / kWh	**70.16 cents / kWh**
Each additional KWh		
- **Energy charge**	70.16 cents / kWh	**70.16 cents / kWh**
- **NWT Stabilization Rate Rider**	0.90 cents / kWh	**0.90 cents / kWh**

If you use 600 kWh, you save $234.48 per month -- that's the amount paid by the GNWT Territorial Power Support Program. If you use more than **600** kWh per month between April 1 and August 31 you will pay 70.16 cents per kWh

Norman Wells

	Your cost	*Actual cost*
Service fee	$18	**$18**
Up to 600 kWh		
- **Energy Charge**	31.08 cents / kWh	**54.84 cents / kWh**
Each additional kWh		
- **Energy Charge**	54.84 cents / kWh	**54.84 cents / kWh**
- **NWT Stabilization Rate Rider**	0.90 cents / kWh	**0.90 cent / kWh**

If you use 600 kWh you save $142.56 per month – that's the amount paid by the GNWT Territorial Power Support Program. If you use more than 600 kWh per month between April 1 and August 31, you will pay 54.84 cents per kWh.

Behchoko/Dettah

	Your cost	*Actual cost*
Service fee	$18	**$18**

MYNTPC
RESIDENTIAL SERVICE
- UNDERSTAND YOUR POWER BILL
- CONNECTIONS AND DISCONNECTIONS
- PAYMENT AND BILLING OPTIONS & LATE PAYMENTS
- RESIDENTIAL ELECTRICAL RATES
BUSINESS SERVICE
NEW CONSTRUCTION SERVICE
TERMS AND CONDITIONS OF SERVICE
NET METERING
TERRITORIAL POWER SUPPORT PROGRAM (TPSP)

Up to 600 kWh		
- Energy charge	31.08 cents / kWh	**35.92 cents / kWh**
Each additional kWh		
- Energy charge	35.92 cents / kWh	**35.92 cents / kWh**
- NWT Stabilization Rate Rider	0.70 cents / kWh	**0.70 cents / kWh**

If you use 600 kWh you save $29.04 per month – that's the amount paid by the GNWT Territorial Power Support Program. If you use more than 600 kWh per month between April 1 and August 31, you will pay 35.92 cents per kWh.

Fort Resolution / Fort Smith

	Your cost	*Actual cost*
Service fee	$18	**$18**
- Energy Charge	24.52 cents / kWh	**24.52 cents / kWh**
- NWT Stabilization Rate Rider	0.99 cents / kWh	**0.99 cents / kWh**

Note: If you are a large customer or a government customer, please contact us for information on your rates.

Empowering Communities

MEDIA CENTRE

BUSINESS OPPORTUNITIES

AWARDED CONTRACTS

SITEMAP

CONTACT US

PRIVACY

LEGAL

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Accounts and Billing (/customer-care/accounts-and-billing)

- How To Read Your Bill (/node/408)
- Ways to Pay Your Bill (/customer-care/accounts-and-billing/ways-to-pay-your-bill)
- Paperless Billing (/customer-care/accounts-and-billing/paperless-billing)
- Late Payments (/customer-care/accounts-and-billing/late-payments)
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- Moving (/customer-care/services/moving)
- Cancelling (/customer-care/services/cancelling)
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Rate Application (/customer-care/rate-application)

General Information (/customer-care/general-information-0)

- Terms and Conditions of Service (/customer-care/general-information/terms-conditions-service-0)

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SAFETY TIPS (/SAFETY-OUTAGES/SAFETY-TIPS)

CURRENT OUTAGES (/SAFETY-OUTAGES/CURRENT-POWER-OUTAGES)

NET METERING PROGRAM (/NODE/759)

WE'RE HERE TO HELP (/CUSTOMER-CARE)

ACCOUNTS AND BILLING (/NODE/172)

SERVICES (/NODE/177)

CUSTOMER RATES

CUSTOMER CARE LINE: 1-866-710-4200

Qulliq Energy Corporation (QEC) provides power to 25 communities across Nunavut to a variety of customers. Customers pay different rates depending on the type of customer they are.

Non-Government Residential (Domestic) Customers – 61.52 cents/kWh

Non-Government Residential rates apply to residential customers who are not living in a public housing unit. These customers are entitled to receive a subsidy of 700 kWh for each 30-day period from April 1 to September 30 and 1000 kWh for each 30-day period from October 1 to March 31. Any consumption that exceeds the subsidy threshold is billed at a Residential Non-Government rate at full cost.

NOTE: Customers are only eligible for this subsidy for one residence. If you have more than one power account, only one is subsidized.

Non-Government Commercial Customers – 50.74 cents/kWh

Non-Government Commercial rates apply to non-governmental commercial customers or business accounts. This also includes any mechanical rooms for multiple units or dwellings and temporary service connections during construction of a unit or building. Customers are billed for their actual meter usage for the month, as well as a base/demand charge.

Note: At QEC's sole discretion, the corporation may install a demand meter on all commercial services.

Government Residential (Domestic) Customers – 93.39 cents/kWh

Government Residential rates apply to residential customers who live in a government owned public housing unit. The tenant is billed directly for 6 cents/kWh and the government is billed the remaining amounts owed (which includes a base charge and metered usage at the Government Residential Rates). When the public housing unit is not occupied the government is billed the full rate.

Government Commercial Customers – 86.97 cents/kWh

Government Commercial rates apply to commercial government accounts or government offices. Customers are billed for their actual meter usage for the month, as well as a base/demand charge.

Note: At QEC's sole discretion, the corporation may install a demand meter on all commercial services.

Municipal Tax-Based Customer (Residential/Domestic - 61.52 cents/kWh & Commercial - 50.74 cents/kWh)

Municipal Tax-Based Customer rates apply to Municipalities that obtains most of its operating costs through community tax revenue. Customers are billed for their actual meter usage for the month, as well as a base charge. Municipalities being reclassified to Municipal Tax-Based Customer must be approved through a regulatory application to the Minister responsible for QEC.

Streetlight Rate

Streetlights are not metered and there is a flat monthly fee per streetlight. The rates differ by community and by the type of street light.

To see streetlight rates, please click here (https://www.qec.nu.ca/sites/default/files/streetlight_rates_effective_april_1_2019_eng_.pdf).

Documents

Streetlight Rates Effective April 1 2019 (https://www.qec.nu.ca/sites/default/files/streetlight_rates_effective_april_1_2019_eng_.pdf)

Rate Schedules Effective October 1, 2022 (https://www.qec.nu.ca/sites/default/files/rate_schedule_-_effective_october_1_2022_-_final_approved_all_languages.pdf)

QEC EMERGENCY LINE: 1-867-222-3807

CUSTOMER CARE LINE: 1-866-710-4200

Baker Lake	1-866-710-4200
Iqaluit	1-867-979-7565
Cambridge Bay	1-800-661-0858
Rankin Inlet	1-800-491-8116

WWW.NSA-NT.CA

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Use our bill calculators to help you:

- Compare electricity price plans
- Compare your current electricity or natural gas bill with a contract offered by an energy retailer

Compare electricity price plans

Residential and small business customers can choose their electricity price plan. **Find out more**.

Power is personal. Depending on how much electricity you use and when you use it, one price plan may suit you better than the others. Use our calculator to see what your total bill would look like under Time-of-Use (TOU), Ultra-Low Overnight (ULO) and Tiered prices, taking into account the other rates charged by your electricity utility (Delivery and Regulatory) and the Ontario Electricity Rebate.

To switch between price plans, you must notify your utility by completing an election form. You can get the election form on your utility's website or by contacting them.

USING THE CALCULATOR

- Get your utility bill, or several months of bills. To use the calculator most effectively, you'll want to know how much electricity you use and when you use it. You can find this information on the Electricity line of your bills, your utility may provide your data when you access your account online, or contact your utility for more detailed information about your electricity use.
- Remember, your monthly use and usage pattern may be different in the winter season than it is in the summer season.

Residential Calculator →

Small Business Calculator →

See how your bill might look on an energy contract

Compare your current bill from your local utility with what to expect if you sign an energy contract with an energy retailer (also called an *electricity retailer* or a *natural gas marketer*). The bill calculator uses the regulated rates for each utility in Ontario. You can enter the contract price offered by the energy retailer to compare.

Electricity for residential +

Electricity for small businesses +

Natural gas for residential +

Natural gas for small businesses +

2022
Comparison of Electricity Prices in Major North American Cities

Rates in effect April 1, 2022

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INTRODUCTION

Every year, Hydro-Québec compares the monthly electricity bills of Québec customers in the residential, commercial, institutional and industrial segments with those of customers of the various utilities serving 21 major North American cities.

This report details the principal conclusions of the comparative analysis of prices in effect on April 1, 2022. There are three sections. The first describes the method used to estimate electricity bills. The second examines the highlights of the seven consumption levels analyzed, with the help of charts. Finally, the third presents the results of the 21 consumption levels for which data were collected and compiled in the form of summary and detailed tables.

The most recent rate adjustments, time-of-use rates, adjustment clauses and applicable taxes, as well as a profile of the utilities in the study, appear in separate appendices.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS[1, 2] (IN ¢/kWh)[3]

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

1) For a monthly consumption of 1,000 kWh; rates in effect April 1, 2022.
2) Average prices excluding taxes.
3) In Canadian currency.

MAJOR NORTH AMERICAN CITIES

AVERAGE PRICES FOR LARGE-POWER CUSTOMERS[1, 2] (IN ¢/kWh)[3]

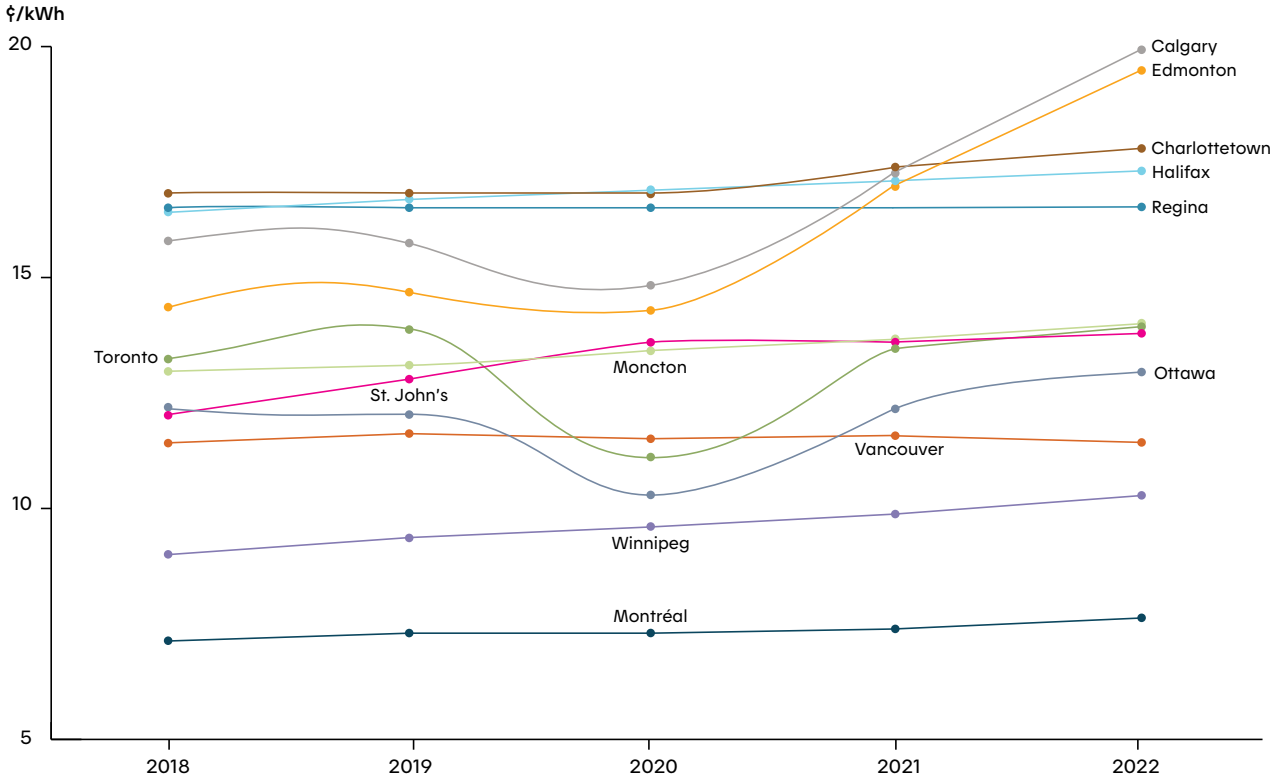
1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW; rates in effect April 1, 2022.
2) Average prices excluding taxes.
3) In Canadian currency.

Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh) – 2018–2022[1, 2, 3, 4]



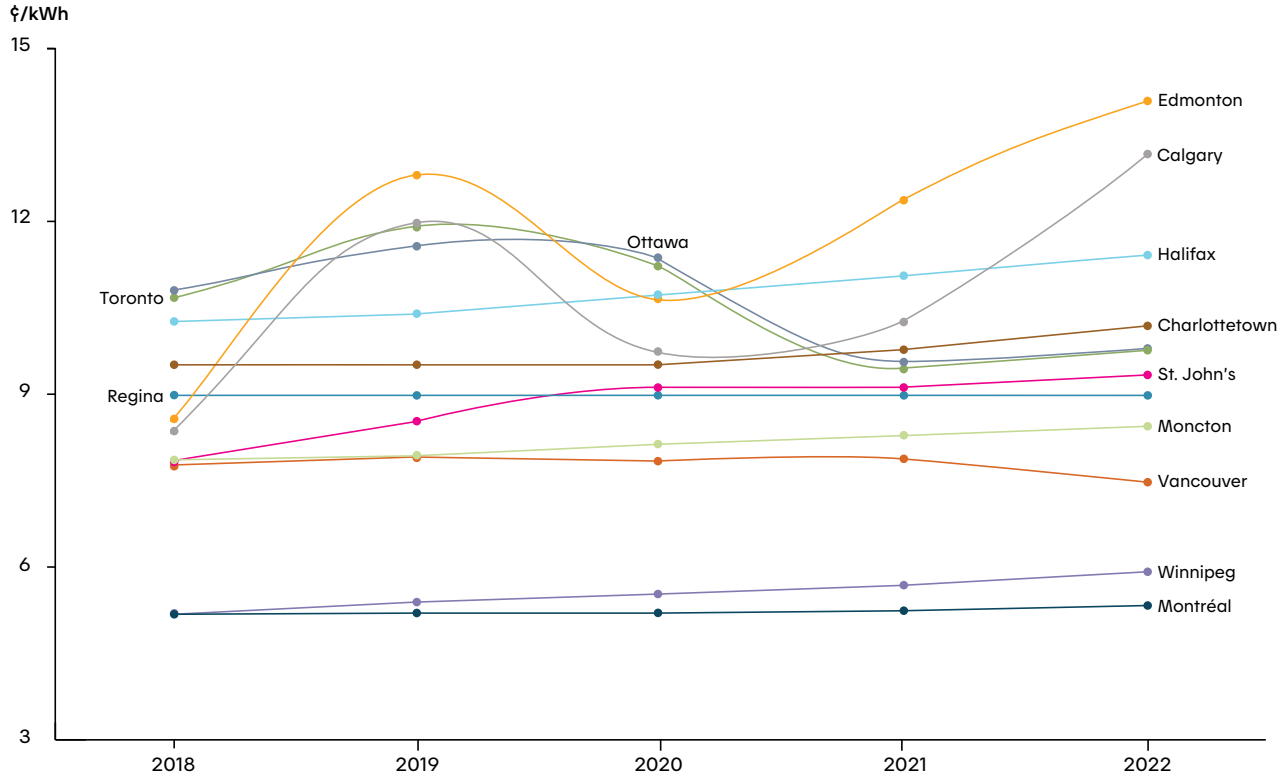
AVERAGE PRICES FOR RESIDENTIAL CUSTOMERS (IN ¢/kWh)[1, 2, 3, 4]

	2018	2019	2020	2021	2022
Canadian Cities					
Montréal, QC	7.13	7.30	7.30	7.39	7.59
Calgary, AB	15.79	15.74	14.83	17.26	19.94
Charlottetown, PE	16.83	16.83	16.83	17.38	17.78
Edmonton, AB	14.35	14.68	14.29	16.99	19.48
Halifax, NS	16.41	16.69	16.89	17.09	17.30
Moncton, NB	12.97	13.10	13.42	13.66	13.94
Ottawa, ON	12.16	12.04	10.29	12.45	12.94
Regina, SK	16.51	16.51	16.51	16.51	16.51
St. John's, NL	12.03	12.80	13.60	13.60	13.76
Toronto, ON	13.24	13.89	11.10	13.43	13.88
Vancouver, BC	11.42	11.62	11.51	11.58	11.39
Winnipeg, MB	9.00	9.37	9.60	9.87	10.24

1) For a monthly consumption of 1,000 kWh.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2018–2022.
4) Average prices excluding taxes.

MAJOR CANADIAN CITIES

OVERVIEW OF CHANGES IN AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh) – 2018–2022[1, 2, 3, 4]



AVERAGE PRICES FOR LARGE-POWER CUSTOMERS (IN ¢/kWh)[1, 2, 3, 4]

	2018	2019	2020	2021	2022
Canadian Cities					
Montréal, QC	5.18	5.20	5.20	5.24	5.33
Calgary, AB	8.32	11.97	9.73	10.25	13.16
Charlottetown, PE	9.51	9.51	9.51	9.77	10.17
Edmonton, AB	8.53	12.80	10.64	12.35	14.08
Halifax, NS	10.26	10.39	10.72	11.05	11.40
Moncton, NB	7.86	7.93	8.13	8.28	8.44
Ottawa, ON	10.80	11.57	11.36	9.57	9.78
Regina, SK	8.98	8.98	8.98	8.98	8.98
St. John's, NL	7.84	8.52	9.12	9.12	9.32
Toronto, ON	10.66	11.91	11.23	9.45	9.76
Vancouver, BC	7.77	7.91	7.84	7.88	7.76
Winnipeg, MB	5.18	5.39	5.53	5.68	5.90

1) For a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW.
2) In Canadian currency.
3) Data from *Comparison of Electricity Prices in Major North American Cities* publications, Hydro-Québec, 2018–2022.
4) Average prices excluding taxes.

METHOD

In addition to Hydro-Québec, this comparative analysis of electricity prices across North America includes 22 utilities: 12 serving the principal cities in the 9 other Canadian provinces, and 10 utilities in American states. The results are based in part on a survey to which 14 utilities responded, and in part on estimates of bills calculated by Hydro-Québec.

The results presented here show the total bill for various consumption levels. If the bill is calculated according to an unbundled rate, it includes all components, including supply, transmission and distribution.

PERIOD COVERED

Monthly bills have been calculated based on rates in effect on April 1, 2022. The most recent rate adjustments applied by the Canadian utilities in the study between April 1, 2021, and April 1, 2022, are shown in Appendix A.

CONSUMPTION LEVELS

Seven consumption levels were selected for analysis. However, data were collected for 21 consumption levels and those results are presented in the detailed tables.

OPTIONAL PROGRAMS

The bills have been calculated according to base rates. Optional rates or programs offered by some utilities to their residential, commercial, institutional or industrial customers have not been taken into account, since the terms and conditions vary considerably from one utility to the next.

GEOGRAPHIC LOCATION

Electricity distributors sometimes apply different rates in the various cities they serve. As well, taxes may vary from one region to another. This, however, is not the case in Québec, where, with the exception of territories north of the 53rd parallel, rates and taxes are applied uniformly. For the purposes of this study, the bill calculations estimate as closely as possible the actual electricity bills of consumers in each target city, based on rates in effect on April 1, 2022.

TIME-OF-USE RATES

The rates applied by some utilities vary depending on the season and/or time of day when energy is consumed. In the United States, for example, a number of utilities set a higher price in summer, when demand for air-conditioning is stronger. In Québec, on the other hand, demand increases in winter because of heating requirements. Thus, for some utilities, April 1 may fall within a period in the year when the price is high, whereas for others it falls in a period when the price is low. An annual average price has therefore been calculated in the case of utilities with time-of-use rates. These utilities and the consumption levels to which time-of-use rates apply are listed in Appendix B.

ADJUSTMENT CLAUSES

The rates of some distributors include clauses that allow them to adjust their customers' electricity bills according to different variables. Since these adjustments may be applied monthly or over a longer period, the bills issued by a given distributor may have varied between April 1, 2021, and April 1, 2022, even though base rates remained the same. Appendix B lists the adjustment clauses taken into account when calculating bills.

TAXES

With the exception of the bills presented in Section 2, taxes are not included in any of the calculations. Appendix C lists the taxes applicable on April 1, 2022, by customer category; those which may be partially or fully refundable are indicated.

EXCHANGE RATE

The exchange rate used to convert bills in U.S. dollars into Canadian dollars is $0.7992 (CA$1 = US$0.7992), the rate in effect at noon on April 1, 2022. The Canadian dollar had thus appreciated by 0.41% relative to the U.S. dollar on April 1, 2021.

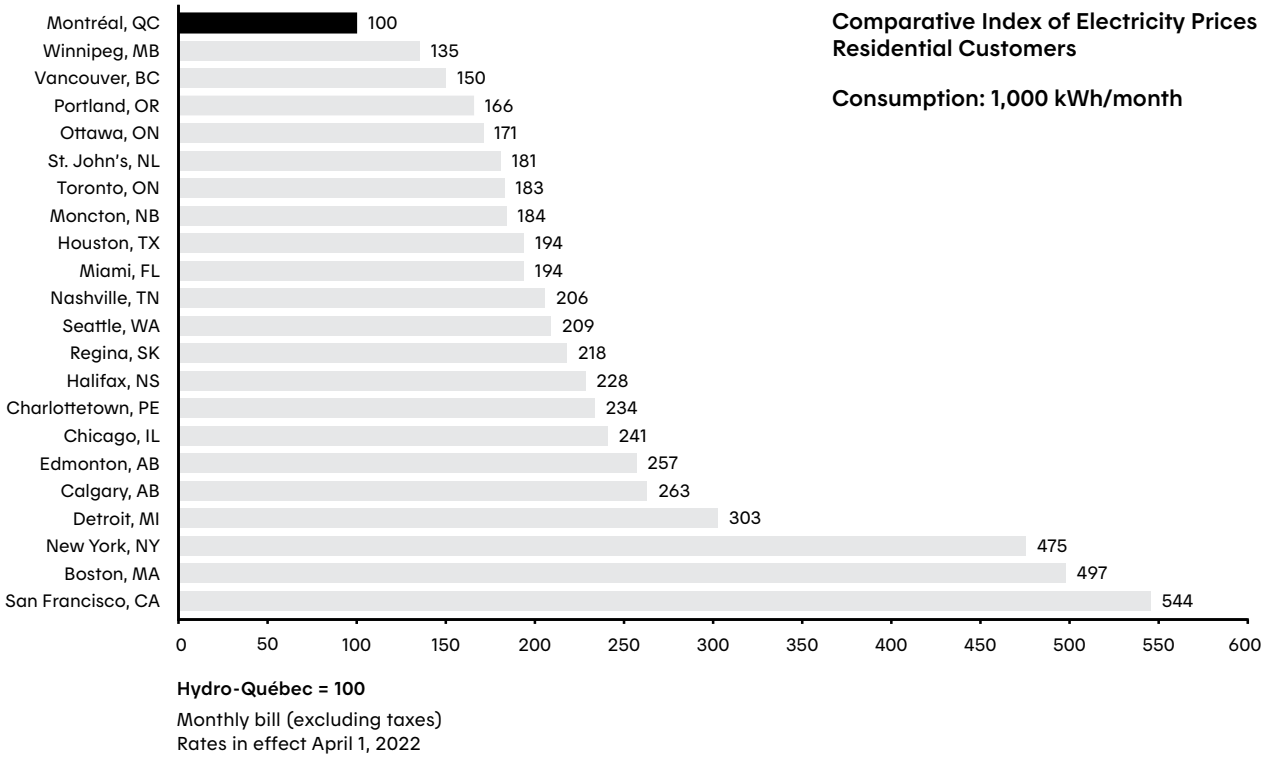
HIGHLIGHTS

The document *Electricity Rates effective April 1, 2022*, sets out Hydro-Québec's rates established in accordance with Schedule 1 of the *Hydro-Québec Act*. Three types of rates are in effect: domestic rates, for residential customers; the industrial rate, for large-power industrial customers; and general rates, for other customers. General rates are applied according to minimum billing demand: small power, medium power and large power. For comparison purposes, the electricity bills of the utilities in the study have been analyzed according to these categories. The industrial rate has been used to calculate the bills of large-power customers.

RESIDENTIAL CUSTOMERS

The rate applicable to Hydro-Québec's residential customers is among the most advantageous in North America. For customers whose monthly consumption is 1,000 kilowatthours (kWh), Montréal is once again in *first* place. Figure 1 illustrates the results of this comparison.

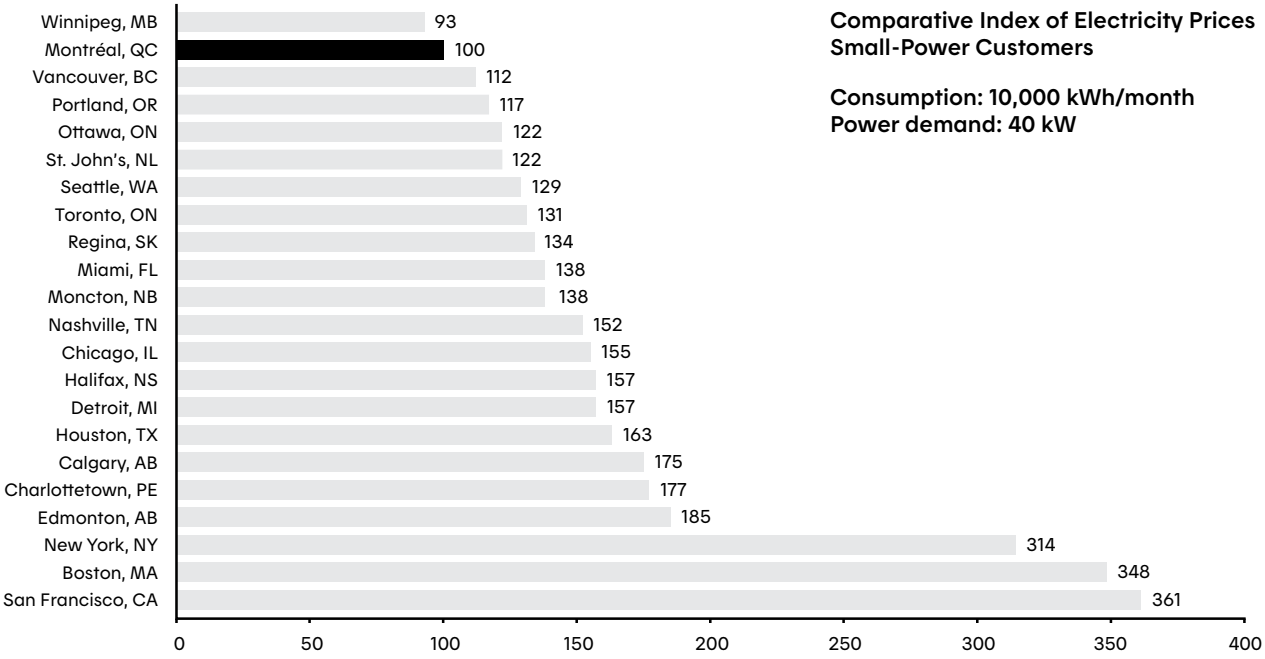
FIGURE 1



SMALL-POWER CUSTOMERS (LESS THAN 100 kW)

The comparison of bills for small-power customers is based on a monthly consumption of 10,000 kWh and a power demand of 40 kilowatts (kW). Again this year, Montréal is in *second* place. Figure 2 shows the comparative index of electricity prices.

FIGURE 2

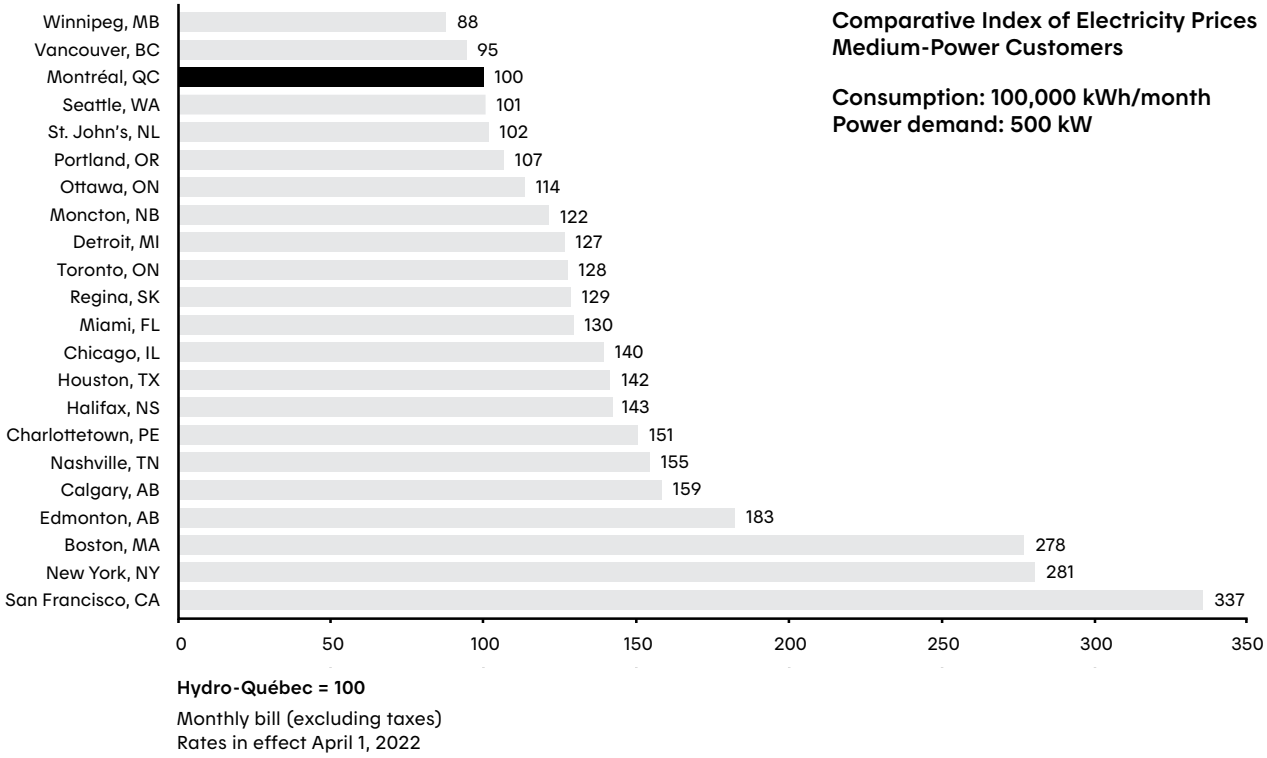


MEDIUM-POWER CUSTOMERS (100 TO 5,000 kW)

Three consumption levels were analyzed for medium-power customers. In all three cases, the bills of Hydro-Québec's customers have remained below the average of the other major North American cities. Figures 3, 4 and 5 show the comparative index of electricity prices for these consumption profiles.

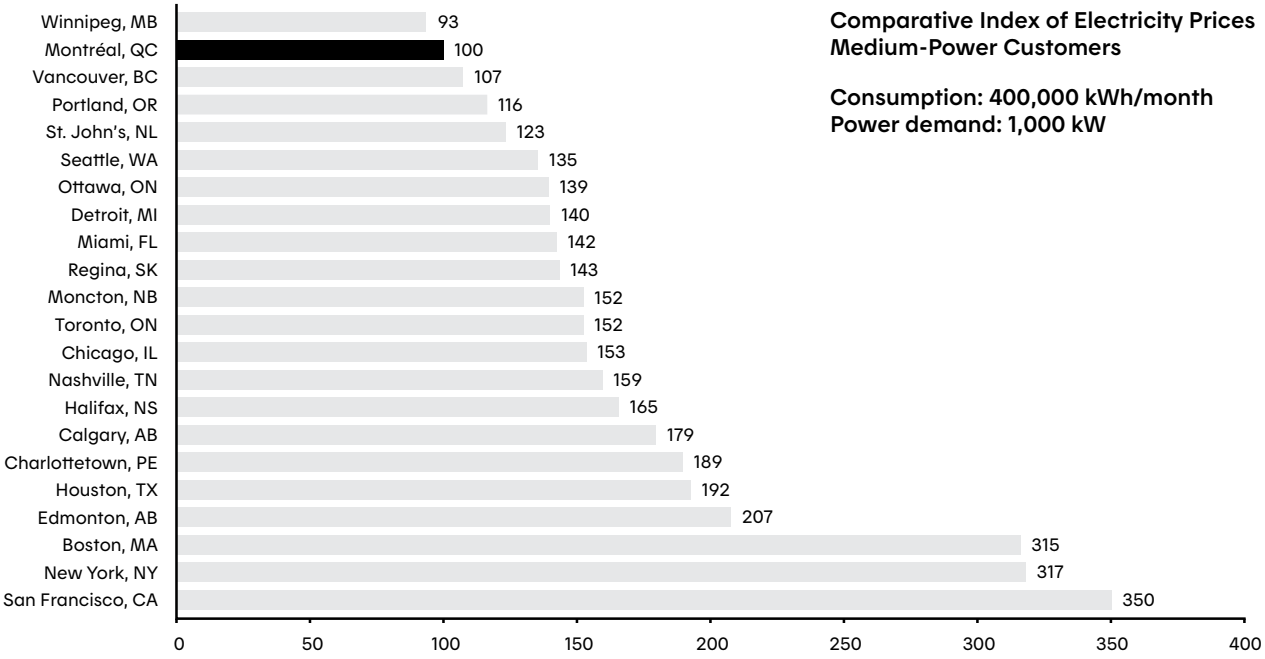
For medium-power customers with a monthly consumption of 100,000 kWh and a power demand of 500 kW, Montréal is once again in *third* place.

FIGURE 3



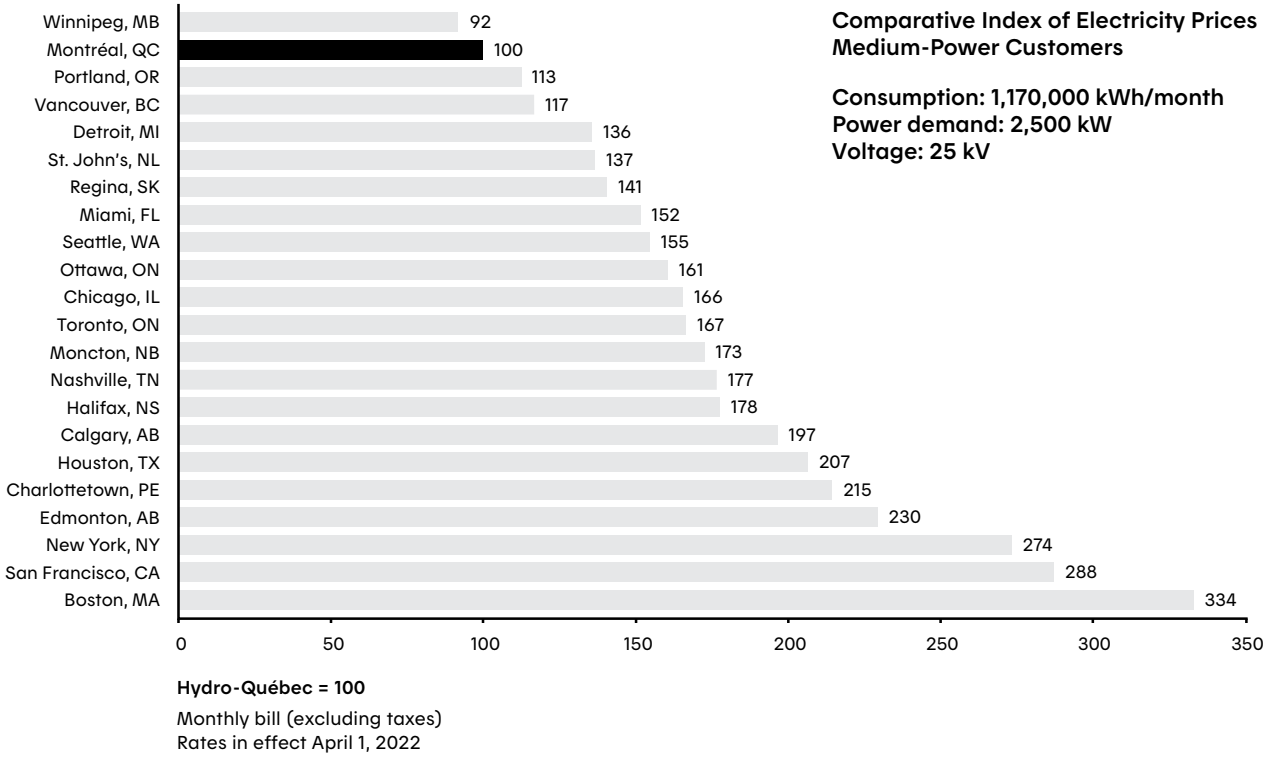
For customers with a monthly consumption of 400,000 kWh and a power demand of 1,000 kW, Montréal ranks *second*.

FIGURE 4



In the case of customers with a monthly consumption of 1,170,000 kWh and a power demand of 2,500 kW, Montréal remains in *second* place.

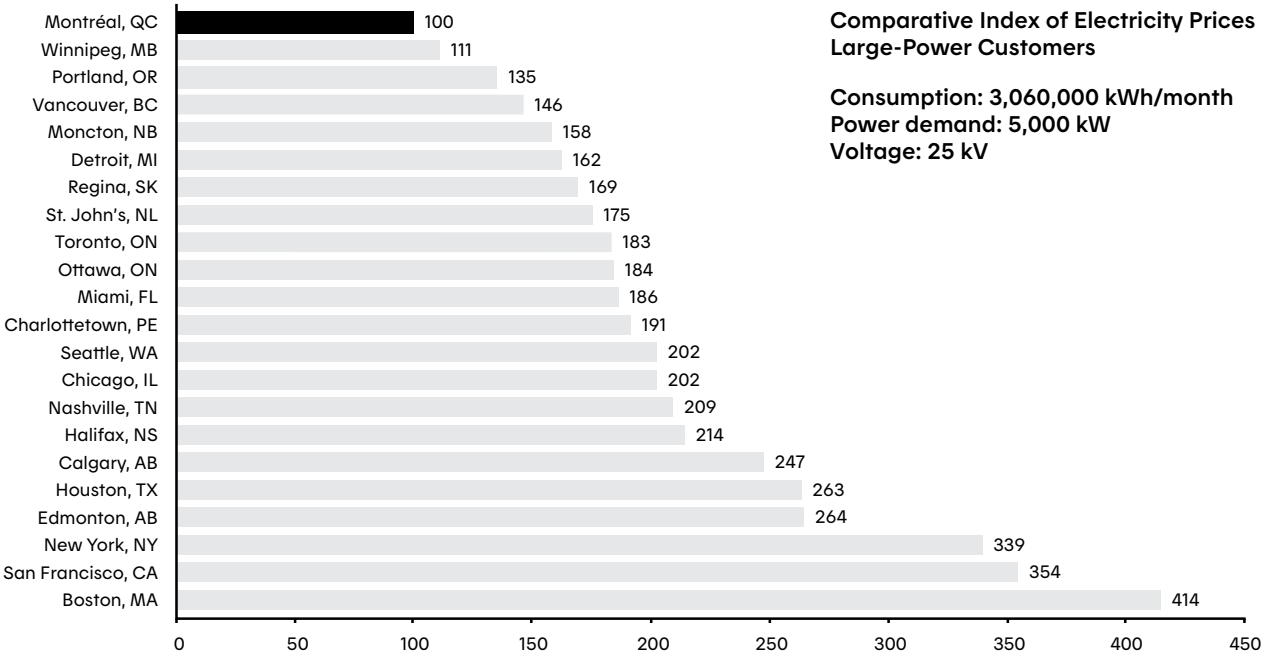
FIGURE 5



LARGE-POWER CUSTOMERS (5,000 kW OR MORE)

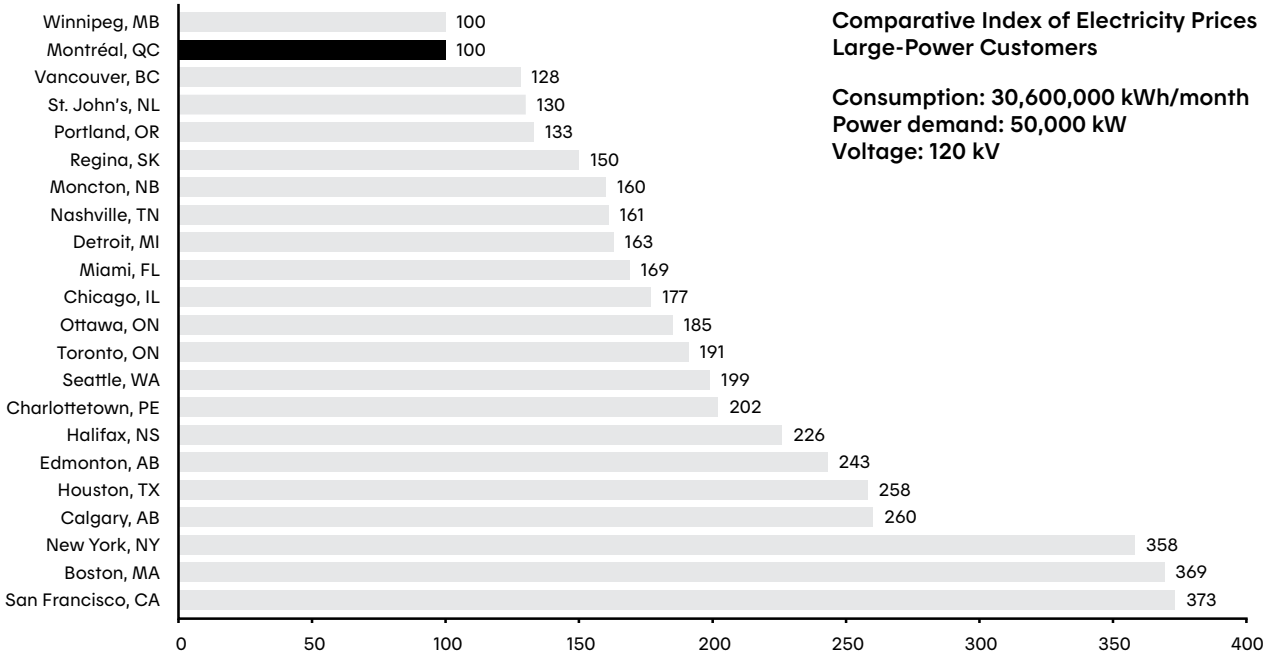
Figure 6 illustrates the comparative index of electricity prices for large-power customers with a monthly consumption of 3,060,000 kWh and a power demand of 5,000 kW. Montréal ranks *first*.

FIGURE 6



For industrial customers with a power demand of 50,000 kW and a load factor of 85%, Montréal is in *second* place, coming in just behind Winnipeg.

FIGURE 7



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Detailed Results

Summary Tables (excluding taxes)

Monthly Bills

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Comparative Index

MONTHLY BILLS ON APRIL 1, 2022
(in C$)

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	75.86	1,041.82	12,674.00	33,495.10	83,102.15	163,058.90	1,543,554.00
Calgary, AB	199.38	1,825.33	20,134.55	59,862.29	163,538.84	402,713.45	4,020,115.96
Charlottetown, PE[3]	177.77	1,849.17	19,195.97	63,140.97	178,842.97	311,180.00	3,111,800.00
Edmonton, AB[4]	194.78	1,927.61	23,135.70	69,364.17	191,297.90	430,870.58	3,746,692.08
Halifax, NS	172.98	1,636.30	18,068.50	55,219.00	147,637.65	348,719.49	3,487,218.84
Moncton, NB	139.35	1,441.17	15,489.37	50,774.37	143,759.37	258,411.84	2,465,040.00
Ottawa, ON	129.43	1,268.55	14,454.21	46,698.99	134,154.64	299,324.01	2,856,155.95
Regina, SK	165.07	1,398.04	16,347.97	48,027.97	117,239.17	274,788.38	2,312,973.29
St. John's, NL[5]	137.58	1,275.75	12,941.20	41,256.08	114,174.40	285,130.07	2,013,256.00
Toronto, ON[3]	138.84	1,365.25	16,261.72	50,903.85	139,022.85	298,524.93	2,946,264.47
Vancouver, BC	113.92	1,168.68	11,993.36	35,856.36	97,616.55	237,343.23	1,976,722.59
Winnipeg, MB	102.44	969.24	11,140.77	31,010.37	76,447.80	180,415.65	1,539,767.52
American Cities							
Boston, MA	377.28	3,630.13	35,177.26	105,544.71	277,420.96	675,655.24	5,693,726.23
Chicago, IL	182.95	1,612.06	17,763.25	51,131.13	137,932.65	329,885.56	2,733,183.47
Detroit, MI[3]	230.08	1,639.81	16,124.27	46,895.91	113,303.65	263,437.16	2,519,216.23
Houston, TX[3]	147.01	1,700.28	17,978.48	64,190.76	172,426.98	429,447.25	3,981,925.95
Miami, FL[3]	147.11	1,437.53	16,465.62	47,619.27	126,201.96	302,553.32	2,609,173.06
Nashville, TN	155.89	1,585.02	19,702.71	53,162.83	146,755.18	341,405.33	2,483,776.45
New York, NY[3]	360.28	3,270.42	35,654.23	106,337.17	227,657.48	552,263.29	5,521,007.15
Portland, OR[3]	126.15	1,216.45	13,535.78	38,879.61	93,682.55	220,907.40	2,059,058.32
San Francisco, CA[3]	412.87	3,764.97	42,741.31	117,151.09	239,254.07	576,616.62	5,753,810.95
Seattle, WA	158.70	1,345.10	12,806.56	45,336.02	128,659.18	329,683.45	3,078,009.47
AVERAGE	**183.90**	**1,744.03**	**19,081.22**	**57,357.18**	**147,733.13**	**341,469.78**	**3,111,474.91**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2022

(in ¢/kWh)[1]

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	7.59	10.42	12.67	8.37	7.10	5.33	5.04
Calgary, AB	19.94	18.25	20.13	14.97	13.98	13.16	13.14
Charlottetown, PE[4]	17.78	18.49	19.20	15.79	15.29	10.17	10.17
Edmonton, AB[5]	19.48	19.28	23.14	17.34	16.35	14.08	12.24
Halifax, NS	17.30	16.36	18.07	13.80	12.62	11.40	11.40
Moncton, NB	13.94	14.41	15.49	12.69	12.29	8.44	8.06
Ottawa, ON	12.94	12.69	14.45	11.67	11.47	9.78	9.33
Regina, SK	16.51	13.98	16.35	12.01	10.02	8.98	7.56
St. John's, NL[6]	13.76	12.76	12.94	10.31	9.76	9.32	6.58
Toronto, ON[4]	13.88	13.65	16.26	12.73	11.88	9.76	9.63
Vancouver, BC	11.39	11.69	11.99	8.96	8.34	7.76	6.46
Winnipeg, MB	10.24	9.69	11.14	7.75	6.53	5.90	5.03
American Cities							
Boston, MA	37.73	36.30	35.18	26.39	23.71	22.08	18.61
Chicago, IL	18.30	16.12	17.76	12.78	11.79	10.78	8.93
Detroit, MI[4]	23.01	16.40	16.12	11.72	9.68	8.61	8.23
Houston, TX[4]	14.70	17.00	17.98	16.05	14.74	14.03	13.01
Miami, FL[4]	14.71	14.38	16.47	11.90	10.79	9.89	8.53
Nashville, TN	15.59	15.85	19.70	13.29	12.54	11.16	8.12
New York, NY[4]	36.03	32.70	35.65	26.58	19.46	18.05	18.04
Portland, OR[4]	12.61	12.16	13.54	9.72	8.01	7.22	6.73
San Francisco, CA[4]	41.29	37.65	42.74	29.29	20.45	18.84	18.80
Seattle, WA	15.87	13.45	12.81	11.33	11.00	10.77	10.06
AVERAGE	**18.39**	**17.44**	**19.08**	**14.34**	**12.63**	**11.16**	**10.17**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2022

(Hydro-Québec = 100)

Summary Table (excluding taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	263	175	159	179	197	247	260
Charlottetown, PE[3]	234	177	151	189	215	191	202
Edmonton, AB[4]	257	185	183	207	230	264	243
Halifax, NS	228	157	143	165	178	214	226
Moncton, NB	184	138	122	152	173	158	160
Ottawa, ON	171	122	114	139	161	184	185
Regina, SK	218	134	129	143	141	169	150
St. John's, NL[5]	181	122	102	123	137	175	130
Toronto, ON[3]	183	131	128	152	167	183	191
Vancouver, BC	150	112	95	107	117	146	128
Winnipeg, MB	135	93	88	93	92	111	100
American Cities							
Boston, MA	497	348	278	315	334	414	369
Chicago, IL	241	155	140	153	166	202	177
Detroit, MI[3]	303	157	127	140	136	162	163
Houston, TX[3]	194	163	142	192	207	263	258
Miami, FL[3]	194	138	130	142	152	186	169
Nashville, TN	206	152	155	159	177	209	161
New York, NY[3]	475	314	281	317	274	339	358
Portland, OR[3]	166	117	107	116	113	135	133
San Francisco, CA[3]	544	361	337	350	288	354	373
Seattle, WA	209	129	101	135	155	202	199
AVERAGE	**242**	**167**	**151**	**171**	**178**	**209**	**202**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

02

Detailed Results

Summary Tables (including taxes)

Monthly Bills

Average Prices

Comparative Index

MONTHLY BILLS ON APRIL 1, 2022
(in C$)

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	87.22	1,197.83	14,571.93	38,511.00	95,546.70	187,476.98	1,774,701.21
Calgary, AB	209.35	1,916.59	21,141.28	62,855.40	171,715.78	422,849.12	4,221,121.75
Charlottetown, PE[3]	204.44	2,126.55	22,075.37	72,612.12	205,669.42	357,857.00	3,578,570.00
Edmonton, AB[4]	204.52	2,023.99	24,292.49	72,832.38	200,862.79	452,414.11	3,934,026.69
Halifax, NS	181.63	1,881.75	20,778.78	63,501.85	169,783.30	401,027.41	4,010,301.67
Moncton, NB	160.25	1,657.35	17,812.78	58,390.53	165,323.28	297,173.62	2,834,796.00
Ottawa, ON	149.70	1,467.24	16,333.26	52,769.86	151,594.74	338,236.13	3,227,456.23
Regina, SK	196.54	1,766.96	20,548.61	61,079.93	150,013.68	353,629.51	3,007,443.97
St. John's, NL[5]	158.22	1,467.11	14,882.38	47,444.49	131,300.56	327,899.58	2,315,244.40
Toronto, ON[3]	160.59	1,579.08	18,375.74	57,521.35	157,095.82	337,333.17	3,329,278.85
Vancouver, BC	121.61	1,227.11	12,593.03	37,649.18	102,497.38	249,210.39	2,075,558.72
Winnipeg, MB	117.42	1,136.44	13,062.55	36,359.66	85,353.97	201,434.07	1,719,150.45
American Cities							
Boston, MA	377.28	3,848.70	37,292.71	111,808.73	293,787.15	715,339.91	6,024,146.33
Chicago, IL	194.94	1,709.21	18,647.94	54,485.79	147,365.88	353,491.47	2,938,319.91
Detroit, MI[3]	250.78	1,820.19	17,897.94	52,054.46	125,767.05	292,415.25	2,796,330.01
Houston, TX[3]	148.48	1,836.38	19,419.36	69,401.89	186,586.22	464,748.62	4,309,860.04
Miami, FL[3]	172.45	1,804.54	20,727.20	59,508.11	157,322.85	376,168.18	3,208,796.14
Nashville, TN	155.89	1,695.97	21,081.90	56,884.23	157,028.04	365,303.70	2,657,640.80
New York, NY[3]	391.53	3,646.43	39,753.51	118,562.75	253,830.99	615,755.86	6,155,745.88
Portland, OR[3]	128.16	1,236.09	13,756.68	39,508.89	95,278.49	224,685.26	2,094,360.72
San Francisco, CA[3]	413.24	3,956.97	44,915.91	123,158.79	251,655.96	606,596.10	6,052,987.99
Seattle, WA	158.70	1,345.10	12,806.56	45,336.02	128,659.18	329,683.45	3,078,009.47
AVERAGE	**197.41**	**1,924.89**	**21,034.90**	**63,283.52**	**162,910.87**	**375,942.22**	**3,424,720.33**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

AVERAGE PRICES ON APRIL 1, 2022

(in ¢/kWh)[1]

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[2]**	**5,000 kW[2]**	**50,000 kW[3]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	8.72	11.98	14.57	9.63	8.17	6.13	5.80
Calgary, AB	20.94	19.17	21.14	15.71	14.68	13.82	13.79
Charlottetown, PE[4]	20.44	21.27	22.08	18.15	17.58	11.69	11.69
Edmonton, AB[5]	20.45	20.24	24.29	18.21	17.17	14.78	12.86
Halifax, NS	18.16	18.82	20.78	15.88	14.51	13.11	13.11
Moncton, NB	16.03	16.57	17.81	14.60	14.13	9.71	9.26
Ottawa, ON	14.97	14.67	16.33	13.19	12.96	11.05	10.55
Regina, SK	19.65	17.67	20.55	15.27	12.82	11.56	9.83
St. John's, NL[6]	15.82	14.67	14.88	11.86	11.22	10.72	7.57
Toronto, ON[4]	16.06	15.79	18.38	14.38	13.43	11.02	10.88
Vancouver, BC	12.16	12.27	12.59	9.41	8.76	8.14	6.78
Winnipeg, MB	11.74	11.36	13.06	9.09	7.30	6.58	5.62
American Cities							
Boston, MA	37.73	38.49	37.29	27.95	25.11	23.38	19.69
Chicago, IL	19.49	17.09	18.65	13.62	12.60	11.55	9.60
Detroit, MI[4]	25.08	18.20	17.90	13.01	10.75	9.56	9.14
Houston, TX[4]	14.85	18.36	19.42	17.35	15.95	15.19	14.08
Miami, FL[4]	17.25	18.05	20.73	14.88	13.45	12.29	10.49
Nashville, TN	15.59	16.96	21.08	14.22	13.42	11.94	8.69
New York, NY[4]	39.15	36.46	39.75	29.64	21.69	20.12	20.12
Portland, OR[4]	12.82	12.36	13.76	9.88	8.14	7.34	6.84
San Francisco, CA[4]	41.32	39.57	44.92	30.79	21.51	19.82	19.78
Seattle, WA	15.87	13.45	12.81	11.33	11.00	10.77	10.06
AVERAGE	**19.74**	**19.25**	**21.03**	**15.82**	**13.92**	**12.29**	**11.19**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) Supply voltage of 120 kV, customer-owned transformer.
4) These bills have been estimated by Hydro-Québec and may differ from actual bills.
5) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
6) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

COMPARATIVE INDEX ON APRIL 1, 2022

(Hydro-Québec = 100)

Summary Table (including taxes)

	Residential Customers	Small-Power Customers	Medium-Power Customers			Large-Power Customers	
Power demand		**40 kW**	**500 kW**	**1,000 kW**	**2,500 kW[1]**	**5,000 kW[1]**	**50,000 kW[2]**
Consumption	**1,000 kWh**	**10,000 kWh**	**100,000 kWh**	**400,000 kWh**	**1,170,000 kWh**	**3,060,000 kWh**	**30,600,000 kWh**
Load factor		**35%**	**28%**	**56%**	**65%**	**85%**	**85%**
Canadian Cities							
Montréal, QC	100	100	100	100	100	100	100
Calgary, AB	240	160	145	163	180	226	238
Charlottetown, PE[3]	234	178	151	189	215	191	202
Edmonton, AB[4]	234	169	167	189	210	241	222
Halifax, NS	208	157	143	165	178	214	226
Moncton, NB	184	138	122	152	173	159	160
Ottawa, ON	172	122	112	137	159	180	182
Regina, SK	225	148	141	159	157	189	169
St. John's, NL[5]	181	122	102	123	137	175	130
Toronto, ON[3]	184	132	126	149	164	180	188
Vancouver, BC	139	102	86	98	107	133	117
Winnipeg, MB	135	95	90	94	89	107	97
American Cities							
Boston, MA	433	321	256	290	307	382	339
Chicago, IL	224	143	128	141	154	189	166
Detroit, MI[3]	288	152	123	135	132	156	158
Houston, TX[3]	170	153	133	180	195	248	243
Miami, FL[3]	198	151	142	155	165	201	181
Nashville, TN	179	142	145	148	164	195	150
New York, NY[3]	449	304	273	308	266	328	347
Portland, OR[3]	147	103	94	103	100	120	118
San Francisco, CA[3]	474	330	308	320	263	324	341
Seattle, WA	182	112	88	118	135	176	173
AVERAGE	**226**	**161**	**144**	**164**	**171**	**201**	**193**

1) Supply voltage of 25 kV, customer-owned transformer.
2) Supply voltage of 120 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

03

Detailed Results

Residential Customers

Monthly Bills

Average Prices

Comparative Index

RESIDENTIAL CUSTOMERS

Monthly Bills on April 1, 2022
(in C$)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	52.17	60.06	75.86	166.49	263.98
Calgary, AB	135.17	156.57	199.38	370.60	541.82
Charlottetown, PE[1]	120.32	139.47	177.77	330.97	453.77
Edmonton, AB	132.28	153.12	194.78	361.47	528.16
Halifax, NS	112.17	132.44	172.98	335.13	497.28
Moncton, NB	95.81	110.33	139.35	255.45	371.55
Ottawa, ON	90.65	103.59	129.43	232.84	336.26
Regina, SK	111.72	129.50	165.07	307.35	449.63
St. John's, NL[2]	91.86	107.10	137.58	259.52	381.45
Toronto, ON[1]	99.19	112.41	138.84	244.59	350.33
Vancouver, BC	64.42	79.42	113.92	251.90	389.89
Winnipeg, MB	67.48	79.13	102.44	195.68	288.92
American Cities					
Boston, MA	239.08	285.16	377.28	745.80	1,114.31
Chicago, IL	121.60	142.08	182.95	346.63	510.29
Detroit, MI[1]	142.98	172.01	230.08	462.34	694.60
Houston, TX[1]	106.39	124.08	147.01	288.54	430.06
Miami, FL[1]	96.16	113.14	147.11	308.00	468.88
Nashville, TN	107.55	123.66	155.89	284.81	418.73
New York, NY[1]	233.01	275.43	360.28	699.68	1,039.08
Portland, OR[1]	83.88	97.97	126.15	265.50	404.85
San Francisco, CA[1]	235.86	297.57	412.87	976.35	1,593.44
Seattle, WA	97.37	117.82	158.70	322.24	485.78
AVERAGE	**119.87**	**141.46**	**183.90**	**364.18**	**546.05**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Average Prices on April 1, 2022
(in ¢/kWh)[1]

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	8.35	8.01	7.59	8.32	8.80
Calgary, AB	21.63	20.88	19.94	18.53	18.06
Charlottetown, PE[2]	19.25	18.60	17.78	16.55	15.13
Edmonton, AB	21.16	20.42	19.48	18.07	17.61
Halifax, NS	17.95	17.66	17.30	16.76	16.58
Moncton, NB	15.33	14.71	13.94	12.77	12.39
Ottawa, ON	14.50	13.81	12.94	11.64	11.21
Regina, SK	17.87	17.27	16.51	15.37	14.99
St. John's, NL[3]	14.70	14.28	13.76	12.98	12.72
Toronto, ON[2]	15.87	14.99	13.88	12.23	11.68
Vancouver, BC	10.31	10.59	11.39	12.60	13.00
Winnipeg, MB	10.80	10.55	10.24	9.78	9.63
American Cities					
Boston, MA	38.25	38.02	37.73	37.29	37.14
Chicago, IL	19.46	18.94	18.30	17.33	17.01
Detroit, MI[2]	22.88	22.93	23.01	23.12	23.15
Houston, TX[2]	17.02	16.54	14.70	14.43	14.34
Miami, FL[2]	15.39	15.09	14.71	15.40	15.63
Nashville, TN	17.21	16.49	15.59	14.24	13.96
New York, NY[2]	37.28	36.72	36.03	34.98	34.64
Portland, OR[2]	13.42	13.06	12.61	13.27	13.50
San Francisco, CA[2]	37.74	39.68	41.29	48.82	53.11
Seattle, WA	15.58	15.71	15.87	16.11	16.19
AVERAGE	**19.18**	**18.86**	**18.39**	**18.21**	**18.20**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

RESIDENTIAL CUSTOMERS

Comparative Index on April 1, 2022
(Hydro-Québec = 100)

Consumption	625 kWh	750 kWh	1,000 kWh	2,000 kWh	3,000 kWh
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	259	261	263	223	205
Charlottetown, PE[1]	231	232	234	199	172
Edmonton, AB	254	255	257	217	200
Halifax, NS	215	221	228	201	188
Moncton, NB	184	184	184	153	141
Ottawa, ON	174	172	171	140	127
Regina, SK	214	216	218	185	170
St. John's, NL[2]	176	178	181	156	144
Toronto, ON[1]	190	187	183	147	133
Vancouver, BC	123	132	150	151	148
Winnipeg, MB	129	132	135	118	109
American Cities					
Boston, MA	458	475	497	448	422
Chicago, IL	233	237	241	208	193
Detroit, MI[1]	274	286	303	278	263
Houston, TX[1]	204	207	194	173	163
Miami, FL[1]	184	188	194	185	178
Nashville, TN	206	206	206	171	159
New York, NY[1]	447	459	475	420	394
Portland, OR[1]	161	163	166	159	153
San Francisco, CA[1]	452	495	544	586	604
Seattle, WA	187	196	209	194	184
AVERAGE	**230**	**236**	**242**	**219**	**207**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

04

Detailed Results

Small-Power Customers

Monthly Bills

Average Prices

Comparative Index

SMALL-POWER CUSTOMERS

Monthly Bills on April 1, 2022
(in C$)

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	89.99	218.62	1,041.82	1,906.24	2,822.15
Calgary, AB	177.51	385.65	1,825.33	3,041.59	4,186.52
Charlottetown, PE[1]	164.90	398.77	1,849.17	3,151.37	4,516.47
Edmonton, AB	161.05	399.77	1,927.61	3,803.93	5,323.69
Halifax, NS	126.30	309.66	1,636.30	2,844.50	4,090.75
Moncton, NB	129.05	303.67	1,441.17	2,507.37	3,596.37
Ottawa, ON	111.76	268.09	1,268.55	2,084.39	3,500.81
Regina, SK	133.66	304.52	1,398.04	2,687.72	3,650.47
St. John's, NL[2]	112.24	294.63	1,275.75	2,199.91	3,172.77
Toronto, ON[1]	132.93	299.46	1,365.25	2,260.65	3,766.10
Vancouver, BC	102.96	256.45	1,168.68	1,866.24	2,909.74
Winnipeg, MB	91.88	210.44	969.24	1,985.12	2,632.42
American Cities					
Boston, MA	265.72	681.44	3,630.13	7,030.14	9,610.26
Chicago, IL	185.27	418.02	1,612.06	2,760.56	3,982.87
Detroit, MI[1]	136.43	352.31	1,639.81	2,283.57	4,053.89
Houston, TX[1]	124.74	422.20	1,700.28	2,904.07	4,231.16
Miami, FL[1]	122.31	301.31	1,437.53	2,655.24	3,540.94
Nashville, TN	181.29	392.51	1,585.02	3,646.25	4,474.14
New York, NY[1]	298.39	928.77	3,270.42	6,136.12	8,066.71
Portland, OR[1]	116.42	273.52	1,216.45	2,099.25	2,993.26
San Francisco, CA[1]	300.58	780.98	3,764.97	6,115.94	9,079.62
Seattle, WA	100.88	269.02	1,345.10	1,949.45	3,071.20
AVERAGE	**153.01**	**384.99**	**1,744.03**	**3,087.26**	**4,421.47**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Average Prices on April 1, 2022
(in ¢/kWh)[1]

Power demand	6 kW	14 kW	40 kW	100 kW	100 kW
Consumption	750 kWh	2,000 kWh	10,000 kWh	14,000 kWh	25,000 kWh
Load factor	17%	20%	35%	19%	35%
Canadian Cities					
Montréal, QC	12.00	10.93	10.42	13.62	11.29
Calgary, AB	23.67	19.28	18.25	21.73	16.75
Charlottetown, PE[2]	21.99	19.94	18.49	22.51	18.07
Edmonton, AB	21.47	19.99	19.28	27.17	21.29
Halifax, NS	16.84	15.48	16.36	20.32	16.36
Moncton, NB	17.21	15.18	14.41	17.91	14.39
Ottawa, ON	14.90	13.40	12.69	14.89	14.00
Regina, SK	17.82	15.23	13.98	19.20	14.60
St. John's, NL[3]	14.97	14.73	12.76	15.71	12.69
Toronto, ON[2]	17.72	14.97	13.65	16.15	15.06
Vancouver, BC	13.73	12.82	11.69	13.33	11.64
Winnipeg, MB	12.25	10.52	9.69	14.18	10.53
American Cities					
Boston, MA	35.43	34.07	36.30	50.22	38.44
Chicago, IL	24.70	20.90	16.12	19.72	15.93
Detroit, MI[2]	18.19	17.62	16.40	16.31	16.22
Houston, TX[2]	16.63	21.11	17.00	20.74	16.92
Miami, FL[2]	16.31	15.07	14.38	18.97	14.16
Nashville, TN	24.17	19.63	15.85	26.04	17.90
New York, NY[2]	39.79	46.44	32.70	43.83	32.27
Portland, OR[2]	15.52	13.68	12.16	14.99	11.97
San Francisco, CA[2]	40.08	39.05	37.65	43.69	36.32
Seattle, WA	13.45	13.45	13.45	13.92	12.28
AVERAGE	**20.40**	**19.25**	**17.44**	**22.05**	**17.69**

1) In Canadian currency.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Newfoundland Power rates.

SMALL-POWER CUSTOMERS

Comparative Index on April 1, 2022
(Hydro-Québec = 100)

Power demand	**6 kW**	**14 kW**	**40 kW**	**100 kW**	**100 kW**
Consumption	**750 kWh**	**2,000 kWh**	**10,000 kWh**	**14,000 kWh**	**25,000 kWh**
Load factor	**17%**	**20%**	**35%**	**19%**	**35%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	197	176	175	160	148
Charlottetown, PE[1]	183	182	177	165	160
Edmonton, AB	179	183	185	200	189
Halifax, NS	140	142	157	149	145
Moncton, NB	143	139	138	132	127
Ottawa, ON	124	123	122	109	124
Regina, SK	149	139	134	141	129
St. John's, NL[2]	125	135	122	115	112
Toronto, ON[1]	148	137	131	119	133
Vancouver, BC	114	117	112	98	103
Winnipeg, MB	102	96	93	104	93
American Cities					
Boston, MA	295	312	348	369	341
Chicago, IL	206	191	155	145	141
Detroit, MI[1]	152	161	157	120	144
Houston, TX[1]	139	193	163	152	150
Miami, FL[1]	136	138	138	139	125
Nashville, TN	201	180	152	191	159
New York, NY[1]	332	425	314	322	286
Portland, OR[1]	129	125	117	110	106
San Francisco, CA[1]	334	357	361	321	322
Seattle, WA	112	123	129	102	109
AVERAGE	**170**	**176**	**167**	**162**	**157**

1) These bills have been estimated by Hydro-Québec and may differ from actual bills.
2) Newfoundland Power rates.

05

Detailed Results

Medium-Power Customers

Monthly Bills

Average Prices

Comparative Index

MEDIUM-POWER CUSTOMERS

Monthly Bills on April 1, 2022
(in C$)

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW[1]
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	12,674.00	18,031.00	25,348.00	33,495.10	83,102.15
Calgary, AB	20,134.55	30,278.65	39,574.09	59,862.29	163,538.84
Charlottetown, PE[2]	19,195.97	31,605.97	38,320.97	63,140.97	178,842.97
Edmonton, AB[3]	23,135.70	36,021.59	43,592.39	69,364.17	191,297.90
Halifax, NS	18,068.50	27,609.50	36,137.00	55,219.00	147,637.65
Moncton, NB	15,489.37	25,389.37	30,974.37	50,774.37	143,759.37
Ottawa, ON	14,454.21	23,449.62	28,708.17	46,698.99	134,154.64
Regina, SK	16,347.97	24,021.97	32,679.97	48,027.97	117,239.17
St. John's, NL[4]	12,941.20	21,320.59	24,654.89	41,256.08	114,174.40
Toronto, ON[2]	16,261.72	25,738.26	32,140.29	50,903.85	139,022.85
Vancouver, BC	11,993.36	17,932.16	23,978.76	35,856.36	97,616.55
Winnipeg, MB	11,140.77	15,632.77	22,026.37	31,010.37	76,447.80
American Cities					
Boston, MA	35,177.26	52,872.46	70,154.32	105,544.71	277,420.96
Chicago, IL	17,763.25	25,655.99	35,345.63	51,131.13	137,932.65
Detroit, MI[2]	16,124.27	23,568.33	32,218.12	46,895.91	113,303.65
Houston, TX[2]	17,978.48	30,042.99	40,061.74	64,190.76	172,426.98
Miami, FL[2]	16,465.62	23,861.76	32,826.98	47,619.27	126,201.96
Nashville, TN	19,702.71	26,696.37	39,175.51	53,162.83	146,755.18
New York, NY[2]	35,654.23	53,205.03	71,235.56	106,337.17	227,657.48
Portland, OR[2]	13,535.78	19,596.03	26,998.32	38,879.61	93,682.55
San Francisco, CA[2]	42,741.31	59,876.50	84,538.58	117,151.09	239,254.07
Seattle, WA	12,806.56	23,004.25	25,170.51	45,336.02	128,659.18
AVERAGE	**19,081.22**	**28,882.33**	**37,993.66**	**57,357.18**	**147,733.13**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Average Prices on April 1, 2022
(in ¢/kWh)[1]

Power demand	500 kW	500 kW	1,000 kW	1,000 kW	2,500 kW[2]
Consumption	100,000 kWh	200,000 kWh	200,000 kWh	400,000 kWh	1,170,000 kWh
Load factor	28%	56%	28%	56%	65%
Canadian Cities					
Montréal, QC	12.67	9.02	12.67	8.37	7.10
Calgary, AB	20.13	15.14	19.79	14.97	13.98
Charlottetown, PE[3]	19.20	15.80	19.16	15.79	15.29
Edmonton, AB[4]	23.14	18.01	21.80	17.34	16.35
Halifax, NS	18.07	13.80	18.07	13.80	12.62
Moncton, NB	15.49	12.69	15.49	12.69	12.29
Ottawa, ON	14.45	11.72	14.35	11.67	11.47
Regina, SK	16.35	12.01	16.34	12.01	10.02
St. John's, NL[5]	12.94	10.66	12.33	10.31	9.76
Toronto, ON[3]	16.26	12.87	16.07	12.73	11.88
Vancouver, BC	11.99	8.97	11.99	8.96	8.34
Winnipeg, MB	11.14	7.82	11.01	7.75	6.53
American Cities					
Boston, MA	35.18	26.44	35.08	26.39	23.71
Chicago, IL	17.76	12.83	17.67	12.78	11.79
Detroit, MI[3]	16.12	11.78	16.11	11.72	9.68
Houston, TX[3]	17.98	15.02	20.03	16.05	14.74
Miami, FL[3]	16.47	11.93	16.41	11.90	10.79
Nashville, TN	19.70	13.35	19.59	13.29	12.54
New York, NY[3]	35.65	26.60	35.62	26.58	19.46
Portland, OR[3]	13.54	9.80	13.50	9.72	8.01
San Francisco, CA[3]	42.74	29.94	42.27	29.29	20.45
Seattle, WA	12.81	11.50	12.59	11.33	11.00
AVERAGE	**19.08**	**14.44**	**19.00**	**14.34**	**12.63**

1) In Canadian currency.
2) Supply voltage of 25 kV, customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland Power rates.

MEDIUM-POWER CUSTOMERS

Comparative Index on April 1, 2022
(Hydro-Québec = 100)

Power demand	**500 kW**	**500 kW**	**1,000 kW**	**1,000 kW**	**2,500 kW**[1]
Consumption	**100,000 kWh**	**200,000 kWh**	**200,000 kWh**	**400,000 kWh**	**1,170,000 kWh**
Load factor	**28%**	**56%**	**28%**	**56%**	**65%**
Canadian Cities					
Montréal, QC	100	100	100	100	100
Calgary, AB	159	168	156	179	197
Charlottetown, PE[2]	151	175	151	189	215
Edmonton, AB[3]	183	200	172	207	230
Halifax, NS	143	153	143	165	178
Moncton, NB	122	141	122	152	173
Ottawa, ON	114	130	113	139	161
Regina, SK	129	133	129	143	141
St. John's, NL[4]	102	118	97	123	137
Toronto, ON[2]	128	143	127	152	167
Vancouver, BC	95	99	95	107	117
Winnipeg, MB	88	87	87	93	92
American Cities					
Boston, MA	278	293	277	315	334
Chicago, IL	140	142	139	153	166
Detroit, MI[2]	127	131	127	140	136
Houston, TX[2]	142	167	158	192	207
Miami, FL[2]	130	132	130	142	152
Nashville, TN	155	148	155	159	177
New York, NY[2]	281	295	281	317	274
Portland, OR[2]	107	109	107	116	113
San Francisco, CA[2]	337	332	334	350	288
Seattle, WA	101	128	99	135	155
AVERAGE	**151**	**160**	**150**	**171**	**178**

1) Supply voltage of 25 kV, customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland Power rates.

06

Detailed Results

Large-Power Customers

Monthly Bills

Average Prices

Comparative Index

LARGE-POWER CUSTOMERS

Monthly Bills on April 1, 2022
(in C$)

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[1]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	138,852.50	163,058.90	296,607.60	897,891.60	1,301,490.00	1,543,554.00
Calgary, AB	322,821.77	402,713.45	764,698.59	2,319,173.23	3,221,199.16	4,020,115.96
Charlottetown, PE[2]	255,020.00	311,180.00	594,280.00	1,801,560.00	2,550,200.00	3,111,800.00
Edmonton, AB[3]	348,211.95	430,870.58	720,529.30	2,170,334.01	3,027,557.36	3,746,692.08
Halifax, NS	281,521.89	348,719.49	663,840.17	2,013,931.71	2,815,242.84	3,487,218.84
Moncton, NB	217,560.12	258,411.84	472,884.00	1,432,068.00	2,062,560.00	2,465,040.00
Ottawa, ON	244,496.42	299,324.01	556,002.65	1,655,820.68	2,307,880.10	2,856,155.95
Regina, SK	225,093.98	274,788.38	446,691.58	1,339,513.04	1,873,125.29	2,312,973.29
St. John's, NL[4]	225,365.78	285,130.07	534,283.60	1,167,415.20	1,665,784.00	2,013,256.00
Toronto, ON[2]	275,196.77	298,524.93	581,052.71	1,742,274.44	2,712,982.85	2,946,264.47
Vancouver, BC	195,225.26	237,343.23	377,362.42	1,144,081.58	1,617,148.83	1,976,722.59
Winnipeg, MB	150,038.85	180,415.65	294,392.96	892,224.64	1,268,615.52	1,539,767.52
American Cities						
Boston, MA	554,529.12	675,655.24	1,082,031.53	3,283,444.94	4,554,446.95	5,693,726.23
Chicago, IL	274,923.72	329,885.56	521,806.48	1,576,203.14	2,183,565.04	2,733,183.47
Detroit, MI[2]	225,984.91	263,437.16	485,966.38	1,468,904.22	2,151,720.73	2,519,216.23
Houston, TX[2]	341,514.32	429,447.25	754,291.32	2,289,089.86	3,119,903.02	3,981,925.95
Miami, FL[2]	252,102.87	302,553.32	501,282.17	1,513,556.44	2,154,578.47	2,609,173.06
Nashville, TN	290,240.17	341,405.33	449,933.70	1,327,291.00	1,976,839.38	2,483,776.45
New York, NY[2]	455,134.31	552,263.29	1,055,781.45	3,199,359.40	4,549,717.36	5,521,007.15
Portland, OR[2]	184,364.67	220,907.40	397,184.16	1,196,978.42	1,719,318.44	2,059,058.32
San Francisco, CA[2]	476,403.35	576,616.62	1,101,753.80	3,335,920.21	4,751,678.22	5,753,810.95
Seattle, WA	257,470.21	329,683.45	582,659.69	1,769,557.13	2,406,803.83	3,078,009.47
AVERAGE	**281,457.86**	**341,469.78**	**601,605.28**	**1,797,117.86**	**2,545,107.15**	**3,111,474.91**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Average Prices on April 1, 2022
(in ¢/kWh)[1]

Power demand	5,000 kW	5,000 kW	10,000 kW	30,000 kW	50,000 kW	50,000 kW
Consumption	2,340,000 kWh	3,060,000 kWh	5,760,000 kWh	17,520,000 kWh	23,400,000 kWh	30,600,000 kWh
Voltage[2]	25 kV	25 kV	120 kV	120 kV	120 kV	120 kV
Load factor	65%	85%	80%	81%	65%	85%
Canadian Cities						
Montréal, QC	5.93	5.33	5.15	5.12	5.56	5.04
Calgary, AB	13.80	13.16	13.28	13.24	13.77	13.14
Charlottetown, PE[3]	10.90	10.17	10.32	10.28	10.90	10.17
Edmonton, AB[4]	14.88	14.08	12.51	12.39	12.94	12.24
Halifax, NS	12.03	11.40	11.53	11.50	12.03	11.40
Moncton, NB	9.30	8.44	8.21	8.17	8.81	8.06
Ottawa, ON	10.45	9.78	9.65	9.45	9.86	9.33
Regina, SK	9.62	8.98	7.76	7.65	8.00	7.56
St. John's, NL[5]	9.63	9.32	9.28	6.66	7.12	6.58
Toronto, ON[3]	11.76	9.76	10.09	9.94	11.59	9.63
Vancouver, BC	8.34	7.76	6.55	6.53	6.91	6.46
Winnipeg, MB	6.41	5.90	5.11	5.09	5.42	5.03
American Cities						
Boston, MA	23.70	22.08	18.79	18.74	19.46	18.61
Chicago, IL	11.75	10.78	9.06	9.00	9.33	8.93
Detroit, MI[3]	9.66	8.61	8.44	8.38	9.20	8.23
Houston, TX[3]	14.59	14.03	13.10	13.07	13.33	13.01
Miami, FL[3]	10.77	9.89	8.70	8.64	9.21	8.53
Nashville, TN	12.40	11.16	7.81	7.58	8.45	8.12
New York, NY[3]	19.45	18.05	18.33	18.26	19.44	18.04
Portland, OR[3]	7.88	7.22	6.90	6.83	7.35	6.73
San Francisco, CA[3]	20.36	18.84	19.13	19.04	20.31	18.80
Seattle, WA	11.00	10.77	10.12	10.10	10.29	10.06
AVERAGE	**12.03**	**11.16**	**10.44**	**10.26**	**10.88**	**10.17**

1) In Canadian currency.
2) Customer-owned transformer.
3) These bills have been estimated by Hydro-Québec and may differ from actual bills.
4) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
5) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

LARGE-POWER CUSTOMERS

Comparative Index on April 1, 2022
(Hydro-Québec = 100)

Power demand	**5,000 kW**	**5,000 kW**	**10,000 kW**	**30,000 kW**	**50,000 kW**	**50,000 kW**
Consumption	**2,340,000 kWh**	**3,060,000 kWh**	**5,760,000 kWh**	**17,520,000 kWh**	**23,400,000 kWh**	**30,600,000 kWh**
Voltage[1]	**25 kV**	**25 kV**	**120 kV**	**120 kV**	**120 kV**	**120 kV**
Load factor	**65%**	**85%**	**80%**	**81%**	**65%**	**85%**
Canadian Cities						
Montréal, QC	100	100	100	100	100	100
Calgary, AB	232	247	258	258	248	260
Charlottetown, PE[2]	184	191	200	201	196	202
Edmonton, AB[3]	251	264	243	242	233	243
Halifax, NS	203	214	224	224	216	226
Moncton, NB	157	158	159	159	158	160
Ottawa, ON	176	184	187	184	177	185
Regina, SK	162	169	151	149	144	150
St. John's, NL[4]	162	175	180	130	128	130
Toronto, ON[2]	198	183	196	194	208	191
Vancouver, BC	141	146	127	127	124	128
Winnipeg, MB	108	111	99	99	97	100
American Cities						
Boston, MA	399	414	365	366	350	369
Chicago, IL	198	202	176	176	168	177
Detroit, MI[2]	163	162	164	164	165	163
Houston, TX[2]	246	263	254	255	240	258
Miami, FL[2]	182	186	169	169	166	169
Nashville, TN	209	209	152	148	152	161
New York, NY[2]	328	339	356	356	350	358
Portland, OR[2]	133	135	134	133	132	133
San Francisco, CA[2]	343	354	371	372	365	373
Seattle, WA	185	202	196	197	185	199
AVERAGE	**203**	**209**	**203**	**200**	**196**	**202**

1) Customer-owned transformer.
2) These bills have been estimated by Hydro-Québec and may differ from actual bills.
3) Bills corresponding to consumption levels of 500 kW or more have been estimated by Hydro-Québec based on the applicable general rate.
4) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

A

Appendix

Rate Adjustments

Across-the-Board Adjustments

Adjustments by
Customer Category

RATE ADJUSTMENTS

Across-the-Board Adjustments

	Before April 2021		Between April 1, 2021, and April 1, 2022		
	Year	%	Date	%	Comments
Canadian Utilities					
Hydro-Québec, QC	2021	1.3	April 1, 2022	2.6	
ENMAX, AB	2021	3.07	January 1, 2022	-1.97	Applicable to distribution component only
Maritime Electric, PE	2021	3.0	March 1, 2022	2.0	
EPCOR, AB	2017	n.a.	—	—	
Nova Scotia Power, NS	2021	n.a.	January 1, 2022	n.a.	
NB Power, NB	2021	1.82	April 1, 2022	2.0	
Hydro Ottawa, ON	2021	n.a.	May 1, 2021	n.a.	
			November 1, 2021	n.a.	
			January 1, 2022	n.a.	
			January 18, 2022	n.a.	
			February 8, 2022	n.a.	
SaskPower, SK	2018	3.5	—	—	
Newfoundland Power, NL[1]	2021	2.5	March 1, 2022	-1.1	
Newfoundland and Labrador Hydro, NL[1]	2021	0.02	February 1, 2022	12.7	
Toronto Hydro, ON	2021	n.a.	January 1, 2022	n.a.	
BC Hydro, BC	2021	1.0	April 1, 2022	0.62	
Manitoba Hydro, MB	2020	n.a.	January 1, 2022	3.6	
Data concerning American utilities not available.					

n.a.: Not available.

1) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

RATE ADJUSTMENTS (Between April 1, 2021, and April 1, 2022)

Adjustments by Customer Category

	Date	Residential Customers %	General-Rate Customers %	Industrial Customers %	Average %
Canadian Utilities					
Hydro-Québec, QC	April 1, 2022	2.6	2.6[1] 2.6[2] 2.6[3]	1.7	2.6
ENMAX, AB	January 1, 2022	-1.96[4]	-1.97[1] -1.97[2] -1.97[3]	n.a.	-1.97[4]
Maritime Electric, PE	March 1, 2022	2.0	2.0	4.0	2.0
EPCOR, AB	—	—	—	—	—
Nova Scotia Power, NS	January 1, 2022	1.2	0.4[1] 2.0[2] 0.002[3]	1.9[5] 3.0[6] 3.0[7]	n.a.
NB Power, NB	April 1, 2022	2.0	2.0	2.0	2.0
Hydro Ottawa, ON	May 1, 2021	-0.03	-0.14	-13.8	n.a.
	November 1, 2021	2.02	2.02	-1.05	n.a.
	January 1, 2022	1.65	1.57	-1.18	n.a.
	January 18, 2022	-13.07	-13.71	—	n.a.
	February 8, 2022	15.04	15.89	—	n.a.
SaskPower, SK	—	—	—	—	—
Newfoundland Power, NL[8]	March 1, 2022	-1.1	-1.1	-1.1	-1.1
Newfoundland and Labrador Hydro, NL[8]	February 1, 2022	—	-	12.7	—
Toronto Hydro, ON	January 1, 2022	n.a.	n.a.	n.a.	n.a.
BC Hydro, BC	April 1, 2022	0.62	0.62	0.62	0.62
Manitoba Hydro, MB	January 1, 2022	3.8	3.1	3.8	3.6
Data concerning American utilities not available.					

n.a.: Not available.

1) Small-power customers.
2) Medium-power customers.
3) Large-power customers.
4) Distribution component only.
5) Small industrial companies.
6) Midsize industrial companies.
7) Large industrial companies.
8) Newfoundland and Labrador Hydro rates for customers with a power demand of 30,000 kW or more; Newfoundland Power rates for all other customer categories.

Note: Because of adjustment clauses (see list in Appendix B), electricity bills issued by a utility may vary, even though base rates have not changed.

B

Appendix

Time-of-Use Rates

Adjustment Clauses

TIME-OF-USE RATES

The utilities listed below apply time-of-use rates for different consumption levels. For the purposes of this study, an annual average has been calculated for utilities whose rates vary according to the season or time of day (or both). In the case of utilities whose supply costs are determined by the market, the average for the month of March 2022 was used.

CenterPoint Energy, TX	All levels
Commonwealth Edison, IL	All levels
Consolidated Edison, NY	All levels
DTE Electric, MI	500–50,000 kW
ENMAX, AB	All levels
EPCOR, AB	All levels
Eversource Energy, MA	General-rate customers: All levels
Hydro Ottawa, ON	All levels
Nashville Electric Service, TN	All levels
Newfoundland Power, NL	Residential customers General-rate customers: 14–10,000 kW
Pacific Gas and Electric, CA	All levels
Pacific Power and Light, OR	1,000–50,000 kW
Seattle City Light, WA	Residential customers General-rate customers: 1,000–50,000 kW
Toronto Hydro, ON	All levels

ADJUSTMENT CLAUSES

Below is a list of utilities whose rates include adjustment clauses that may cause fluctuations in the price of electricity even though base rates have not been adjusted.

BC Hydro, BC	Customer Crisis Fund Deferral Account
CenterPoint Energy, TX	Accumulated Deferred Federal Income Tax Credit Distribution Cost Recovery Factor Energy Efficiency Cost Recovery Factor Nuclear Decommissioning Charge Rate Case Expenses Surcharge Transition Charges Transmission Cost Recovery Factor Unprotected Excess Deferred Income Tax
Commonwealth Edison, IL	Energy Efficiency Pricing & Performance Environmental Cost Recovery Adjustment Energy Transition Assistance Charge Franchise Cost Additions Renewable Energy Adjustment Renewable Energy Distributed Generation Rebate Retail Customer Assessments Zero Emission Adjustment
Consolidated Edison, NY	Adjustment Factors – MSC and MAC Billing and Payment Processing Charge Clean Energy Standard Supply Surcharge Clean Energy Standard Delivery Surcharge Delivery Revenue Surcharge Dynamic Load Management Surcharge Market Supply Charge Market Supply Charge – Capacity Merchant Function Charge Monthly Adjustment Clause Revenue Decoupling Mechanism Adjustment Tax Sur-Credit System Benefits Charge Value of Distributed Energy Resources Cost Recovery
DTE Electric, MI	Energy Waste Reduction Surcharge Low Income Energy Assistance Fund Factor Nuclear Surcharge Power Supply Cost Recovery Clause Renewable Energy Plan Surcharge

ENMAX, AB	Balancing Pool Allocation Rider DAS Adjustment Rider Local Access Fee Quarterly Transmission Access Charge Adjustment Rider Regulated Rate Option Rider Transmission Access Charge Deferral Account Rider Adjustment
EPCOR, AB	Balancing Pool Rider Local Access Fee SAS True-Up Rider Transmission Charge Deferral Account True-Up Rider Utility Payment Deferral Program
Eversource Energy, MA	Attorney General Consultant Expense Basic Service Cost Adjustment Energy Efficiency Charge Grid Modernization Factor Long Term Renewable Contract Adjustment Miscellaneous Charges Net Metering Recovery Surcharge Pension Adjustment Mechanism Performance Based Revenue Adjustment Renewable Energy Charge Residential Assistance Adjustment Clause Revenue Decoupling Adjustment Mechanism Solar Program Cost Adjustment Solar Expansion Cost Recovery Mechanism Solar Massachusetts Renewable Target Storm Cost Recovery Adjustment Storm Reserve Adjustment Mechanism Transition Cost Adjustment Transmission Service Cost Adjustment Vegetation Management 2017 Tax Act Credit
Florida Power and Light, FL	Energy Conservation Cost Recovery Clause Capacity Payment Recovery Clause Environmental Cost Recovery Clause Fuel Cost and Purchase Power Recovery Clause Storm Protection Charge Transition Credit
Hydro Ottawa, ON	Capacity Based Recovery Disposition of Deferral/Variance Accounts Disposition of Global Adjustment Account (2022) Lost Revenue Adjustment Mechanism Recovery Rate Rider for Group 2 Accounts Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge
Maritime Electric, PE	Energy Cost Adjustment Mechanism

Nashville Electric Service, TN	Pandemic Recovery Credit TVA Fuel Cost Adjustment
Newfoundland and Labrador Hydro, NL	CDM Cost Recovery Adjustment Rate Stabilization Plan Adjustment
Nova Scotia Power, NS	Fuel Adjustment Mechanism (AA/BA)
Pacific Gas and Electric, CA	California Climate Credit Competition Transition Charges Energy Cost Recovery Amount New System Generation Charge Nuclear Decommissioning Public Purpose Programs Reliability Services Transmission Rate Adjustments Wildfire Fund Charge Wildfire Hardening Charge
Pacific Power and Light, OR	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act Base Supply Service Community Solar Start-Up Cost Recovery Adjustment Deer Creek Mine Closure Deferred Amounts Adjustment Federal Tax Act Adjustment Independent Evaluator Cost Adjustment Intervenor Funding Adjustment Net Power Costs, Cost-Based Supply Service Oregon Corporate Activity Tax Recovery Adjustment Oregon Solar Incentive Program Deferral Property Sales Balancing Account Adjustment Public Purpose Charge Power Cost Adjustment Mechanism Rate Mitigation Adjustment Renewable Adjustment Clause Renewable Resource Deferral Adjustment Replaced Meter Deferred Amounts Adjustment System Benefits Charge TAM Adjustment for Other Revenues
Toronto Hydro, ON	Capacity Based Recovery (CBR) Disposition of Accounts Receivable Credits Disposition of Derecognition Variance Account Disposition of Expansion Deposits Disposition of Stranded Meter Assets Disposition of Wireless Pole Attachment Revenue Recovery of Monthly Billing Transition Costs Rural or Remote Electricity Rate Protection Charge Smart Metering Entity Charge

C

Appendix

Applicable Taxes

Residential Customers

General-Rate Customers

Industrial Customers

TAXES APPLICABLE TO RESIDENTIAL CUSTOMERS

On April 1, 2022

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill
	Québec sales tax	9.975	To base amount of bill
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	5	To base amount of bill
Moncton, NB	Harmonized sales tax	15	To base amount of bill
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill
Toronto, ON	Harmonized sales tax	13	To base amount of bill
Vancouver, BC	Regional transit levy	$1.90	Monthly
	Goods and services tax	5	To base amount of bill + regional transit levy
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (heating other than electric)
		1.4	To base amount of bill (electric heating)
	Municipal tax	2.5	To base amount of bill (heating other than electric)
		0.5	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax
American Cities			
Boston, MA	None		
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	4	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	Municipal tax	1	To base amount of bill
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.638	To base amount of bill
	Franchise fee	5.955	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
Nashville, TN	None		
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	4.9098	To other components
	Sales tax	4.5	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.25	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS

On April 1, 2022

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable[1])
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (industries other than mining and manufacturing)
		1.4	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.638	To base amount of bill
	Franchise fee	5.955	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO GENERAL-RATE CUSTOMERS (cont'd)

On April 1, 2022

	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4095	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.25	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS

On April 1, 2022

	Tax	% (or other)	Applicable
Canadian Cities			
Montréal, QC	Goods and services tax	5	To base amount of bill (tax refundable)
	Québec sales tax	9.975	To base amount of bill (tax refundable[1])
Calgary, AB	Goods and services tax	5	To base amount of bill
Charlottetown, PE	Harmonized sales tax	15	To base amount of bill (tax refundable)
Edmonton, AB	Goods and services tax	5	To base amount of bill
Halifax, NS	Harmonized sales tax	15	To base amount of bill (tax refundable)
Moncton, NB	Harmonized sales tax	15	To base amount of bill (tax refundable)
Ottawa, ON	Harmonized sales tax	13	To base amount of bill
Regina, SK	Municipal tax	10	To base amount of bill
	Provincial sales tax	6	To base amount of bill + municipal tax
	Carbon levy	¢/kWh	To energy consumption
	Goods and services tax	5	To base amount of bill
St. John's, NL	Harmonized sales tax	15	To base amount of bill (tax refundable)
Toronto, ON	Harmonized sales tax	13	To base amount of bill (tax refundable)
Vancouver, BC	Goods and services tax	5	To base amount of bill
Winnipeg, MB	Provincial sales tax	7	To base amount of bill (industries other than mining and manufacturing)
		1.4	To base amount of bill (mining and manufacturing companies)
	Municipal tax	5	To base amount of bill (heating other than electric)
		1	To base amount of bill (electric heating)
	Goods and services tax	5	To base amount of bill + municipal tax (tax refundable)
American Cities			
Boston, MA	State sales tax	6.25	To a portion of base amount of bill
Chicago, IL	State tax	¢/kWh	Tax varies by energy block
	Municipal tax	¢/kWh	Tax varies by energy block
Detroit, MI	State sales tax	6	To base amount of bill
	City of Detroit utility users' tax	5	To base amount of bill
Houston, TX	State tax	6.25	To base amount of bill
	Municipal tax	1	To base amount of bill
	Transit tax	1	To base amount of bill
Miami, FL	Gross receipts tax/ Regulatory assessment fee	2.638	To base amount of bill
	Franchise fee	5.955	To base amount of bill + gross receipts tax
	Municipal tax	10	To a portion of base amount of bill
	State sales tax	6.95	To base amount of bill + gross receipts tax + franchise fee
	Local tax	1	To base amount of bill + gross receipts tax + franchise fee
Nashville, TN	State sales tax	7	To base amount of bill

1) Commercial customers with revenue below $10 million and customers in the manufacturing sector are entitled to a refund of this tax.

TAXES APPLICABLE TO INDUSTRIAL CUSTOMERS (cont'd)

On April 1, 2022

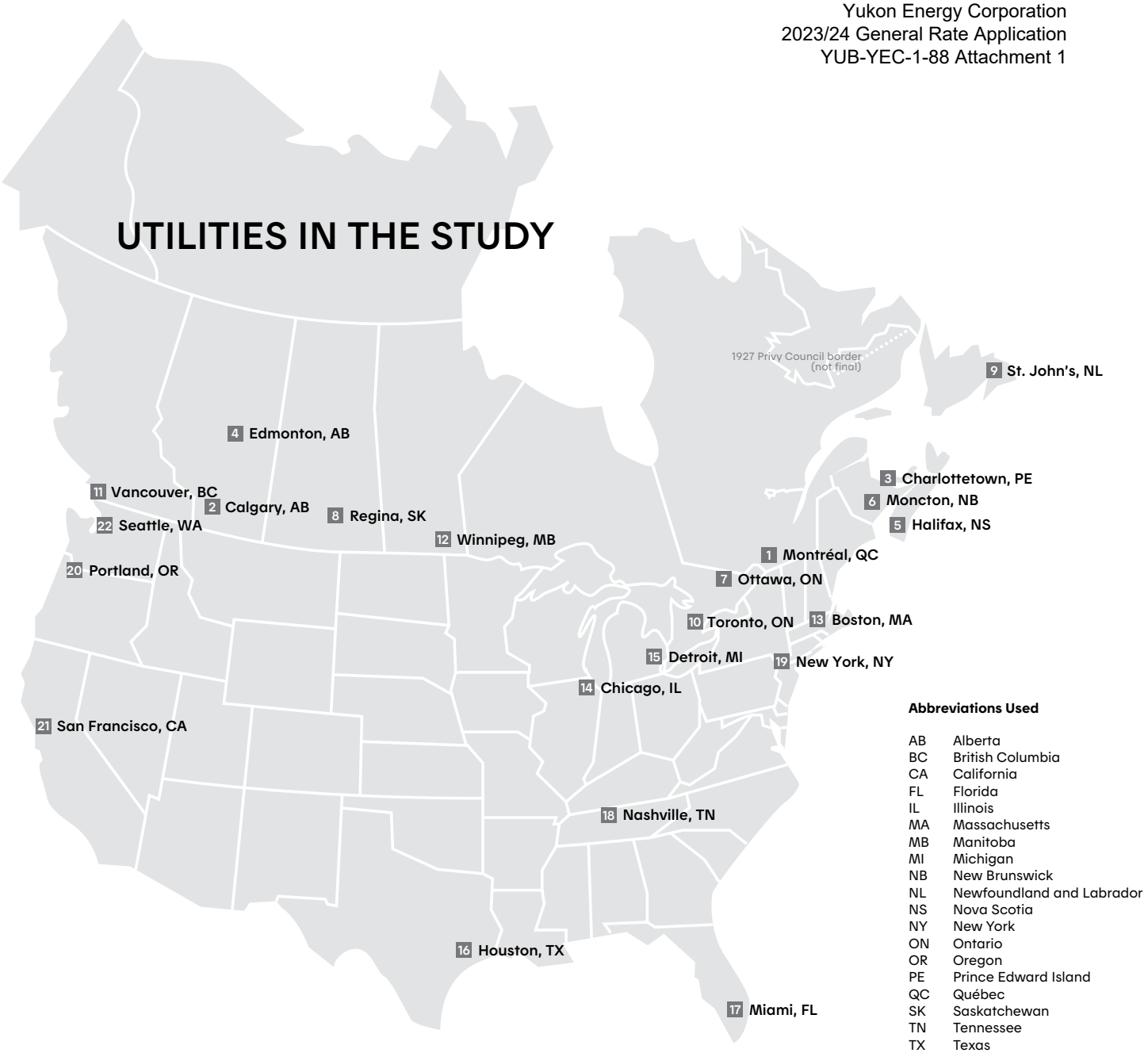
	Tax	% (or other)	Applicable
New York, NY	Commodity gross receipts tax	2.4066	To commodity component
	Delivery gross receipts tax	2.4095	To other components
	Sales tax	8.875	To base amount of bill + gross receipts tax
Portland, OR	Multnomah County business income tax	0.25	To a portion of base amount of bill
	City of Portland franchise tax	1.5	To a portion of base amount of bill
San Francisco, CA	Energy Commission tax	¢/kWh	To energy consumption
	San Francisco utility users' tax	5	To base amount of bill
Seattle, WA	State utility tax	3.8734	Tax included in rate schedule prices
	City of Seattle occupation tax	6	Tax included in rate schedule prices

D

Appendix

Utilities in the Study

UTILITIES IN THE STUDY



Abbreviations Used

AB	Alberta
BC	British Columbia
CA	California
FL	Florida
IL	Illinois
MA	Massachusetts
MB	Manitoba
MI	Michigan
NB	New Brunswick
NL	Newfoundland and Labrador
NS	Nova Scotia
NY	New York
ON	Ontario
OR	Oregon
PE	Prince Edward Island
QC	Québec
SK	Saskatchewan
TN	Tennessee
TX	Texas
WA	Washington

CANADIAN UTILITIES

1- Hydro-Québec
2- ENMAX
3- Maritime Electric
4- EPCOR
5- Nova Scotia Power
6- NB Power
7- Hydro Ottawa
8- SaskPower
9- Newfoundland and Labrador Hydro
(customers with a power demand of 30,000 kW or more)
Newfoundland Power
(all other customer categories)
10- Toronto Hydro
11- BC Hydro
12- Manitoba Hydro

AMERICAN UTILITIES

13- Eversource Energy
14- Commonwealth Edison
15- DTE Electric
16- CenterPoint Energy
17- Florida Power and Light
18- Nashville Electric Service
19- Consolidated Edison
20- Pacific Power and Light
21- Pacific Gas and Electric
22- Seattle City Light

CANADIAN UTILITIES

HYDRO-QUÉBEC
Montréal, Québec

Hydro-Québec, a government-owned company, is one of the largest electric utilities in North America. In accordance with the *Act respecting the Régie de l'énergie* [Québec energy board], it provides a maximum of 165 TWh of heritage pool electricity per year to the Québec market and also purchases power on the markets to meet its customers' needs. The average supply cost of heritage pool electricity, set at 2.79¢/kWh in 1998, has been indexed annually on January 1 since 2014 at a rate corresponding to the annual variation in the average overall Consumer Price Index for Québec. The large-power industrial rate (Rate L) is exempt from this indexation.

Since December 2019, Hydro-Québec's rates have been subject to *An Act to simplify the process for establishing electricity distribution rates*, which called for a rate freeze from April 1, 2020, to March 31, 2021. For the period from 2021 to 2025, the Act provides for an annual adjustment of rates according to changes in the annual average Consumer Price Index for Québec except in the case of Rate L, which is set by the Régie de l'énergie taking into account the competitiveness of the rate and cross-subsidization. As a result, Rate L was indexed at a rate of 1.7% on April 1, 2022, while all other rates were indexed at a rate of 2.6%.

Activities: Generation, transmission and distribution

Installed capacity: 37,248 MW

Main sources: Hydropower generating stations and wind power purchases (more than 99% of power supplied is clean and renewable)

Number of accounts: About 4.5 million residential, commercial, institutional and industrial customer accounts, nine municipal systems and one regional cooperative

Distribution regulator: Régie de l'énergie

Wholesale market: Open

Retail market: –

ENMAX
Calgary, Alberta

Activities: Generation, transmission and distribution

Installed capacity: 1,601 MW

Main sources: Natural gas (91%) and wind (9%)

Number of accounts: More than 700,000

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

MARITIME ELECTRIC
Charlottetown, Prince Edward Island

Activities: Distribution

Installed capacity: About 130 MW for reserve purposes

Main sources: Purchases from NB Power and PEI Energy Corporation

Number of accounts: About 86,000

Distribution regulator: Island Regulatory and Appeals Commission

Wholesale market: –

Retail market: –

EPCOR
Edmonton, Alberta

Activities: Transmission and distribution

Installed capacity: –

Main sources: Market purchases

Number of accounts: About 600,000 customers in all, located throughout Alberta (including more than 413,000 in Edmonton) and in Simcoe County, Ontario (nearly 20,000 customers)

Distribution regulator: Alberta Utilities Commission

Wholesale market: Open

Retail market: Open

NOVA SCOTIA POWER
Halifax, Nova Scotia

Activities: Generation, transmission and distribution

Installed capacity: Over 2,400 MW

Main sources: Coal, petroleum coke, wind, hydropower and other

Number of accounts: More than 536,000 residential, commercial and industrial customers

Distribution regulator: Nova Scotia Utility and Review Board

Wholesale market: –

Retail market: –

NB POWER
Moncton, New Brunswick

Activities: Generation, transmission and distribution

Installed capacity: 3,790 MW

Main sources: Thermal (1,716 MW), hydropower (889 MW), nuclear (660 MW) and combustion turbines (525 MW)

Number of accounts: More than 400,000 direct and indirect customers

Distribution regulator: New Brunswick Energy and Utilities Board

Wholesale market: –

Retail market: –

HYDRO OTTAWA
Ottawa, Ontario

Activities: Generation and distribution

Installed capacity: 128 MW (renewable energy)

Main sources: Purchases from Ontario Power Generation

Number of accounts: About 354,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but electricity supply rate regulated by the Ontario Energy Board

SASKPOWER
Regina, Saskatchewan

Activities: Generation, transmission and distribution

Installed capacity: 4,987 MW

Main sources: Natural gas (43%), coal (31%), hydropower (20%), wind (5%), solar and other (1%)

Number of accounts: About 545,000

Distribution regulator: Saskatchewan Rate Review Panel

Wholesale market: Partially open

Retail market: Partially open

NEWFOUNDLAND AND LABRADOR HYDRO
(customers with a power demand of 30,000 kW or more)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 1,763 MW

Main sources: Hydropower (80%) and fuel-fired (20%) generating stations

Number of accounts: More than 38,000 direct customers

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

NEWFOUNDLAND POWER
(all other customer categories)
St. John's, Newfoundland and Labrador

Activities: Generation, transmission and distribution

Installed capacity: 140 MW

Main sources: Purchases from Newfoundland and Labrador Hydro (93%)

Number of accounts: More than 273,000 customers throughout the island of Newfoundland

Distribution regulator: Newfoundland and Labrador Board of Commissioners of Public Utilities

Wholesale market: –

Retail market: –

TORONTO HYDRO
Toronto, Ontario

Activities: Distribution

Installed capacity: –

Main sources: Purchases from Ontario Power Generation

Number of accounts: About 787,000

Distribution regulator: Ontario Energy Board

Wholesale market: Open

Retail market: Open, but electricity supply rate regulated by the Ontario Energy Board

BC HYDRO
Vancouver, British Columbia

Activities: Generation, transmission and distribution

Installed capacity: About 12,204 MW

Main sources: Hydropower generating stations (about 98%)

Number of accounts: More than 2.1 million

Distribution regulator: British Columbia Utilities Commission

Wholesale market: Open

Retail market: –

MANITOBA HYDRO
Winnipeg, Manitoba

Activities: Generation, transmission and distribution

Installed capacity: 5,608 MW

Main sources: Hydropower (about 96%), thermal and diesel

Number of accounts: About 601,000

Distribution regulator: Manitoba Public Utilities Board

Wholesale market: –

Retail market: –

AMERICAN UTILITIES

EVERSOURCE ENERGY
Boston, Massachusetts

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchases from ISO New England

Number of accounts: Close to 3.1 million residential, commercial and industrial customers in Massachusetts, Connecticut and New Hampshire

Distribution regulator: Massachusetts Department of Public Utilities

Wholesale market: Open

Retail market: Open

COMMONWEALTH EDISON (ComEd)
Chicago, Illinois

Activities: Transmission and distribution

Installed capacity: –

Main sources: Purchases from Midcontinent Independent System Operator

Number of accounts: More than 4 million customers in northern Illinois

Distribution regulator: Illinois Commerce Commission

Wholesale market: Open

Retail market: Open

DTE ELECTRIC
Detroit, Michigan

Activities: Generation, transmission and distribution

Installed capacity: 11,084 MW

Main sources: Coal, nuclear, natural gas, hydropower and other (renewables)

Number of accounts: 2.2 million customers in southeastern Michigan

Distribution regulator: Michigan Public Service Commission

Wholesale market: Open

Retail market: Partially open

CENTERPOINT ENERGY
Houston, Texas

Activities: Generation, transmission and distribution

Installed capacity: About 1,300 MW in Indiana

Main sources: Purchases from the Electric Reliability Council of Texas

Number of accounts: More than 2.5 million

Distribution regulator: Public Utility Commission of Texas

Wholesale market: Open

Retail market: Open

FLORIDA POWER AND LIGHT (FPL)
Miami, Florida

Activities: Generation, transmission and distribution

Installed capacity: Over 28,000 MW

Main sources: Natural gas, nuclear, solar and coal

Number of accounts: More than 5.7 million

Distribution regulator: Florida Public Service Commission

Wholesale market: Open

Retail market: –

NASHVILLE ELECTRIC SERVICE
Nashville, Tennessee

Activities: Distribution

Installed capacity: –

Main sources: Purchases from Tennessee Valley Authority

Number of accounts: More than 420,000

Distribution regulator: Tennessee Valley Authority

Wholesale market: –

Retail market: –

CONSOLIDATED EDISON (ConEd)
New York, New York

Activities: Distribution

Installed capacity: –

Main sources: Purchases from New York Independent System Operator

Number of accounts: 3.4 million customers in the New York metropolitan area and Westchester County

Distribution regulator: New York State Public Service Commission

Wholesale market: Open

Retail market: Open

PACIFIC POWER AND LIGHT
Portland, Oregon

Activities: Generation, transmission and distribution

Installed capacity: 11,550 MW

Main sources: Thermal, hydropower, wind and solar

Number of accounts: More than 791,000 customers across three states (Oregon, Washington and California)

Distribution regulator: Public Utility Commission of Oregon

Wholesale market: Open

Retail market: Partially open

PACIFIC GAS AND ELECTRIC (PG&E)
San Francisco, California

Activities: Generation, transmission and distribution

Installed capacity: 7,662 MW

Main sources: Purchases from California ISO and fuel-fired, hydropower, solar and other generating stations

Number of accounts: 5.5 million

Distribution regulator: California Public Utilities Commission

Wholesale market: Open

Retail market: Partially open

SEATTLE CITY LIGHT
Seattle, Washington

Activities: Generation, transmission and distribution

Installed capacity: 2,006 MW

Main sources: Hydropower, wind, biogas and other generating stations and purchases from Bonneville Power Administration

Number of accounts: More than 478,000 customers in Seattle and surrounding communities

Distribution regulator: City of Seattle

Wholesale market: Open

Retail market: –

Information sources
Annual reports and websites of the Canadian and American utilities in the study.

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Aggregated Generic Load Curve for Residential Electric Water Heaters

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Aggregated Generic Load Curve for Residential Electric Water Heaters

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***Abstract*—Advanced control techniques may be used to regulate the operation of residential appliances to establish a virtual power plant. The electric water heater may be regarded as a "uni-directional battery" and a major component of a hybrid residential energy storage system. One of the main constraints of implementing demand response with EWH relates to the unpredictable customer behavior, which influences the domestic water tank temperature as well as the EWH operation cycle. This study analyzes the operation of multiple water heaters and develops an aggregated generic water heater load curve for the average residential customer based on experimental data retrieved from the A.O. Smith Corporation. An equivalent thermal model capable of capturing the typical customer behavior and estimating the per unit hot water usage was developed. The proposed aggregated generic EWH load curve was validated through an example demand response program, in which the morning peak demand is shed in order to store the surplus PV power at midday in the EWH. Based on the representative hot water draw profile and the electric power profile, the change in average tank temperature was estimated and maintained within the customer acceptable range.**

***Index Terms*—Electric Water Heater (EWH), Generic Curve, Demand Response (DR), Smart Home, Virtual Power Plant (VPP), Smart Grid.**

I. Introduction

The near-ubiquity of Electric water heaters (EWHs) make them one of the most advantageous appliances to participate in the virtual power plant (VPP) operation for residential buildings. Due to the large thermal mass of water tanks, EWHs could be regarded as a heat reservoir as well as an energy sink. The good insulation of EWH tanks lead to high equivalent resistances, resulting in less energy loss [1]. These properties allow EWHs to, for a short period of time, shed grid power while maintaining the water temperature at the reference temperature. On the other hand, EWHs can also be used to absorb surplus PV generation. There are multiple benefits of incorporating EWHs into home energy management as the PV penetration keeps rising. Recent research indicate that incorporating EWHs could lead up to 30% reduction in battery capacity for residential homes [2].

The water heating load makes up a great portion of a typical total house load [3]. The unpredictability of customer behavior makes quantifying the benefits of controlling EWHs difficult. A typical aggregated load for EWHs has a morning and evening peak [4]. User comfort needs to be ensured while implementing the demand response (DR) calls for the monitoring of the water tank temperature. The water temperature in the tank must be high enough to meet the user demand and cannot exceed the stipulated safety reference. However, technologies such as mixing valves may be integrated to allow the water tank temperature up to 145F remain within acceptable operation range [5], [6].

In previous studies, the hot water draws for 48 representative days were evaluated based on measured data from California homes [7]. The proposed schedules are used in the California Building Energy Code Compliance for Residencial buildings (CBECC-Res) [8]. Another study calculates the aggregated EWH load by relating to the hot water usage activities [9]. An EWH demonstration report shows the reduction in both power and electricity usage that is possible [10]. The Smart Water Heater Simulator in the EPRI DERMS simulation framework emulates a smart water heater with communications capabilities [11].

In this paper, the aggregated generic load for residential EWHs is proposed based on experimental data retrieved from the industrial collaborator, A.O. Smith. The dynamic relationship among EWH working status, tank temperature, and hot water usage is identified and evaluated using equivalent thermal models. An aggregated generic curve for hot water usage, which represents the average user behavior, is also proposed. The VPP control through DR was implemented by shifting the morning peak to the midday when the PV generation is relatively high. The results from this study indicate that maintaining the tank temperature within acceptable ranges is possible while participating in DR.

II. Electric Water Heater Project Overview

In 2018, the A.O. Smith group in conjunction with Lowe's initiated a program to explore the potential benefits of smart EWHs for the grid and analyze trends in customer behaviors. Approximately 800 customers with the "EnergySmart" EWH model participated in the program, in which appliance usage data was retrieved and evaluated. The EWH heater models include an optional CTA-2045 port adaptor and utility communication module to ensure smart communication with their provider. (Fig. 1).

The first year of this two-year project witnessed a growing number of participants, peaking at nearly 500 electric water

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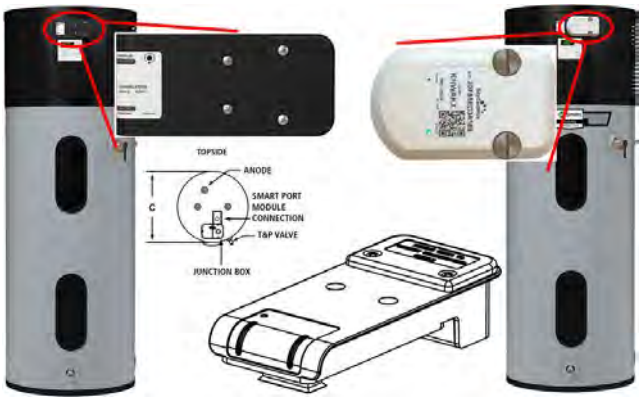

Fig. 1. The illustrative parts of A.O.Smith "EnergySmart" model and CTA-2045 standard port. The "EnergySmart" model is smart grid ready and implements standardized communications for demand response.

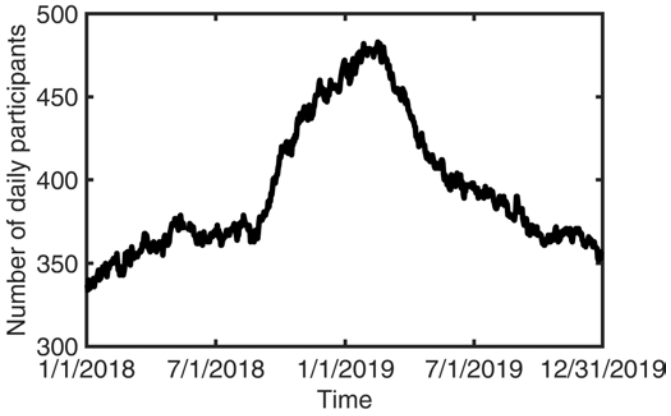

Fig. 2. Daily number of EWH in service. Approximately 800 participants were involved in the program and an increase from inception till early 2019 can be observed before the gradual decline.

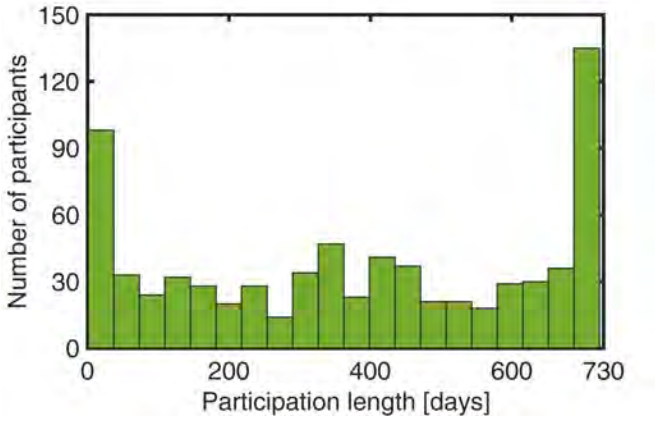

Fig. 3. Participant engagement over the duration of the research. Reduction in the number of participants in some cases were attributed to changes in internet settings and monitoring hardware devices being disconnected.

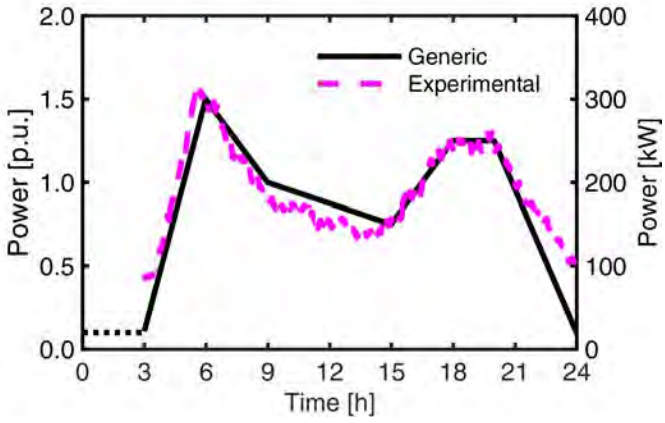

Fig. 4. Example day aggregated power transfer. The aggregated generic profile was developed based on data retrieved from 450 EWHs.

heaters recorded per day in early 2019 (Fig. 2). Based on the reported data, up to 100 participants opted out of the program at inception and only 140 EWHs participated through the entire length of the project (Fig. 3).

III. Mathematical Model

This study presents an approach for developing an aggregated generic power curve for aggregated EWHs based on the experimental data retrieved from the Lowe's project. The operation status (ON or OFF) of each EWH participating in the programs was collected and analyzed at 1-minute resolution. For this program, it is assumed that all the EWH are rated for 5kW.

The daily power curve for EWHs is influenced by multiple factors including the hot water usage, outlet and inlet water temperature, duct insulation, heating element efficiency and other user-influenced parameters. Hence, there is variation in the power curve from one EWH unit to the other. A typical residential EWH would normally have two or three short heating cycles daily. Only when the number of EWHs being analyzed is fairly large is the aggregated EWH power relatively smooth with trends.

In another experimental study conducted in the approximately the same time frame, a different group of researchers from Oak ridge National Lab considered a field pilot demonstrator that involves only 50 EWHs [4]. The results from such limited number of samples somewhat follow the trend noted in our proposed generic load curve, but the variations are much larger due to limited aggregation effect. In this study, a systematic search was carried out to recursively reducing the number of EWHs until the trend established by the full data was still obvious. To this end, only workdays with more than 450 EWHs online were analyzed. The generic EWH power curve of the selected workdays is presented in Fig. 4.

The measured power profile from 450 EWHs were used to develop an aggregated generic load profile to represent the typical power flow for multiple EWHs (Fig. 4). The estimated standby loss in the early morning was low because of the improved insulation [4]. This proposed aggregated generic EWH load curve can be employed for estimating expected morning

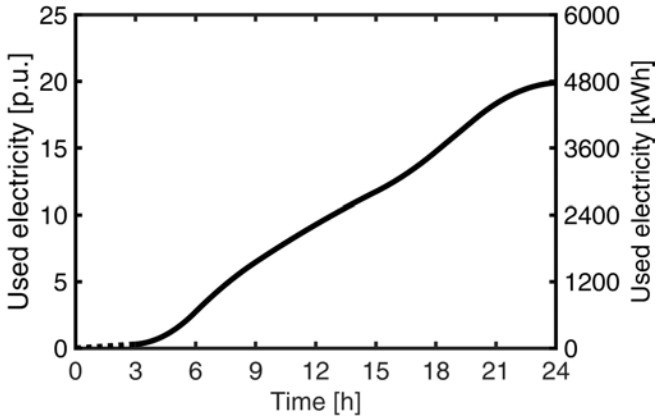

Fig. 5. Example day EWH cummulated energy. The average daily electricity usage for each EWH is approximately 11kWh.

Table I
THE P.U. VALUE OF AVERAGE EWH POWER

Hour	0	3	6	9	15	18	20	24
Power [p.u.]	0.1	0.33	1.5	1	0.75	1.25	1.25	0.33

and evening peak demands as well as evaluate the anticipated standby losses from multiple EWHs. This techniques uses the least amount of data points to develop an aggregated generic curve that can be used for the modeling of aggregated EWH load (Table I). Based on the aggregated generic curve the cumulative energy for the 450 EWHs considered was recorded as 5,016kWh for the example day evaluated (Fig. 5). Hence, the average daily electricity usage for each EWH can be computed as 11kWh. In this approach, the per-unit base value for the proposed aggregated generic curve is defined as:

$$P_{base} = \frac{E \cdot N}{T}, \tag{1}$$

where, E is the average daily electricity usage; N, the total number of EWHs; and T, the duration in hours.

The equivalent thermal model is used to establish the daily hot water usage in the study. The water temperature is mostly determined by the input electric power, the standby heat loss, and the hot water draw activities. These three major factors are included in the heat transfer function of the water temperature, as follows,

$$C\frac{\mathrm{d}\theta_T(t)}{\mathrm{d}t} = S(t)P_H(t) - \frac{1}{R}[\theta_T(t) - \theta_A] - \rho c_p W(t)\,[\theta_T(t) - \theta_{W,C}], \tag{2}$$

where C is the equivalent capacitance; $S(t)$, the ON/OFF status; defined respectively as:

$$C = V \cdot \rho \cdot c_p. \tag{3}$$

Table II
PARAMETERS FOR THE EQUIVALENT EWH MODEL.

Parameter	Value or unit
Density of water ρ	993 $^{kg}/_{m^3}$
Specific heat capacity of water c_p	4,179 $^{J}/_{kg^\circ C}$
Room air temperature θ_A	22 °C
Temperature of cold water $\theta_{W,C}$	10 °C
Rated EWH heating rate P_H	4.5 kW
Water tank volume V	50 gallon
Equivalent resistance R	1400 $^{^\circ C}/_{kW}$
Water temperature in the tank θ_T	°C
Hot water draw W	m^3/s

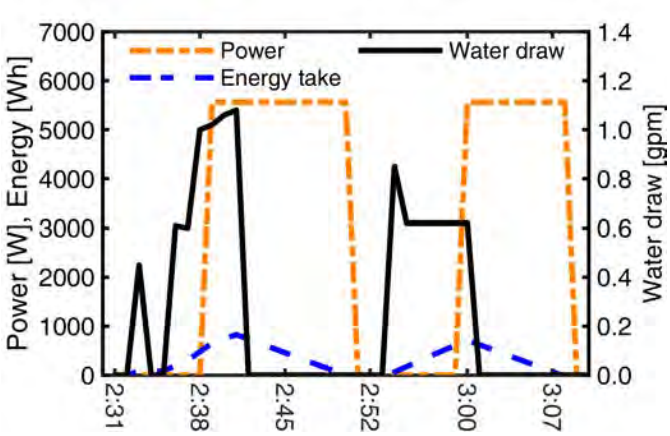

Fig. 6. Simulation results obtained based on (2). The data compares satisfactorily with the experimental results from the NREL test published in the EPRI report [12].

$$S(t) = \begin{cases} 0, & \text{if } S(t-1) = 1 \;\&\; \theta_T(t) \geq \theta_H(t) \\ 1, & \text{if } S(t-1) = 0 \;\&\; \theta_T(t) \leq \theta_L(t) \\ S(t-1), & \text{otherwise,} \end{cases} \tag{4}$$

where θ_L and θ_H are the lower and upper band of the water tank temperature. The definitions of other parameters are listed in Table. II. It is worth noting that the water temperature in the tank θ_T and the hot water draw W have only their units listed in the table.

The performance test of a CTA-2045 equipped A. O. Smith water heater was conducted by National Renewable Energy Laboratory (NREL) and reported by Electric Power Research Institute (EPRI) [12]. The case of "Normal Operation" from the report was used for the validation of the parameter values listed in Table. II, apart from the "Rated EWH heating rate P_H, which was set to 5.5kW only for this validation. The simulation results, which were plotted in the same style as the report, show satisfactory results (Fig. 6). The term "Energy take" reflects the temperature of the water tank.

When the working status and power of the EWH and the tank temperature are known, (2) can be re-written to calculate

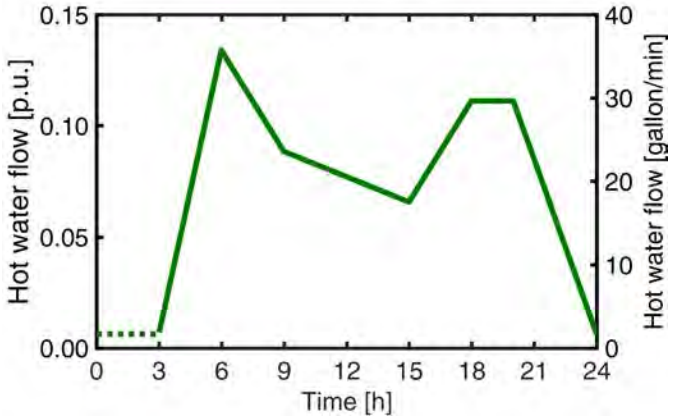

Fig. 7. The calculated total daily hot water draw for 450 EWHs. The total daily hot water usage was 27,427 gallons for 450 EWHs, an average of 61 gallons.

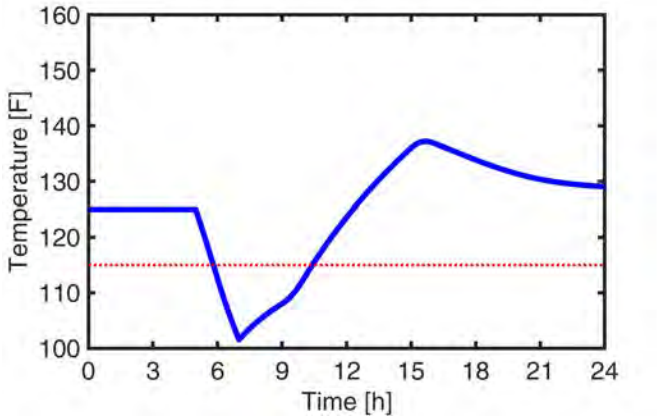

Fig. 9. The average tank temperature for the EWHs participating in demand response. The red dotted line marks the common preference of 115°F. The example shows a significant reduction in tank temperature in the early hours for the extreme condition when all the EWH were turned off. The recovery around midday means EWHs can be used as storage for surplus PV power.

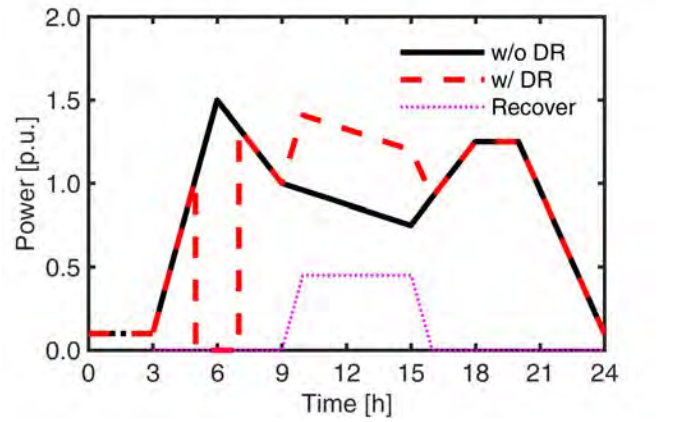

Fig. 8. Example demand response for aggregated electric water heater. This approach demonstrates how the peak demand at the early hour of the day (5:00–7:00) can be shifted to some time around midday (9:00–16:00), when solar generation is relatively high.

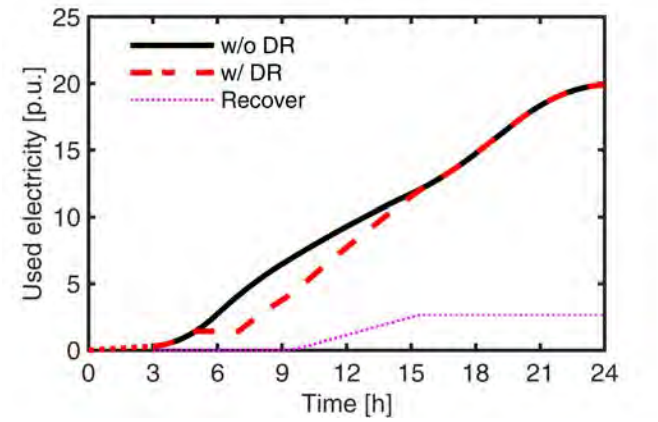

Fig. 10. Accumulated electricity usage of the EWH. from 5:00–7:00, the used electricity remained the same in the DR case. In the afternoon, the electricity usage caught up with the w/o DR case.

the hot water usage:

$$W(t) = \frac{S(t)P(t) - \frac{1}{R}[\theta_T(t) - \theta_A]}{\rho c_p [\theta_T(t) - \theta_{W,C}]}. \quad (5)$$

In the study, it is assumed that the average temperature of all the water tanks is constant. When $\theta_T(t) = 125F$, $S(t) = 1$, and EWH power $P(t)$ was replaced with the value of aggregated eneric curve from Fig. 4, the aggregated hot water draw was calculated using (5) and is shown in Fig. 7. The daily hot water draw for each EWH was 61 gallons.

The per unit hot water draw was calculated based on (5), with $\theta_T(t) = 125F$, $S(t) = 1$, and the EWH power $P(t)$ replaced by the value from Fig. 4. The aggregated generic hot water draw shown in Fig. 7 stands for the representative user behavior and does not change when the DR is implemented.

IV. Example Cases of Demand Response (DR)

The objective of demand response is to shed the EWH load at critical time, and recover during the midday, as follows:

$$P_D(t) = \begin{cases} 0, & \text{if } t \in T_D \\ P_O(t) + P_R(t), & \text{if } t \in T_R, \end{cases} \quad (6)$$

where P_D is the aggregated EWH load with DR; P_R, the aggregated recover power; P_O, the original aggregated EWH load without DR; T_D, the set of time when DR is required; T_R, the set of time when recovery is required. It is worth noting that not all EHWs will turn on during the recovery. Therefore, it is assumed that $P_O(t) + P_R(t) < P \cdot N$.

An example demand response with $T_D = [5:00, 7:00]$ and $T_R = [9:00, 16:00]$ is shown in Fig. 8. The fixed hot water flow from Fig. 7 was used for the DR study. When the EWH's load was shed in the morning, the water temperature in the tank dropped (Fig. 9). The example case in Fig. 9 shows the

maximum load reduction case scenario, which will result in the temperature being too low. In which case some of the EWH will not meet the customer comfort. A practical home energy management would put the customer comfort as priority and avoid the tank temperature being too low. The tank temperature increased in the midday as the EWH started to recover from 9:00. In this example, it is assumed that the total electricity usage for the w/ and w/o DR cases are equal (Fig. 10).

V. Conclusion

The proposed aggregated generic curves for the residential EWH load and the hot water usage in this paper are the first of its kind to the best of the authors‘ knowledge. The aggregated generic curves were obtained based on two years of experimental data from approximately 800 users collected by the industrial collaborator, A.O. Smith. While monitoring the temperature in the tank, this load curve may be employed by EWHs for multiple applications including establishing peak demand, power variation, daily energy profile and unit utilization factor.

The detailed technical benefits of the example aggregated generic curve were demonstrated through a demand response program, in which the operation of the EWH was regulated to reduce the peak power and store surplus solar generation. In this approach, the residential setup was considered as a virtual power plant with the EWH regarded as a “uni-directional” energy storage operating within customer predefined water tank temperature limits.

Acknowledgment

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Add Load Shape(s):

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USA

Region

ECAR

Season and Day Type

- [x] Peak Season, Peak Weekday
- [x] Peak Season, Average Weekday
- [x] Peak Season, Average Weekend
- [x] Off Peak Season, Peak Weekday
- [x] Off Peak Season, Average Weekday
- [x] Off Peak Season, Average Weekend

Sector and End Use:

Commercial | Residential | Industrial

- [ ] Cooling
- [ ] Heating
- [ ] Lighting, External *("All Regions" only)*
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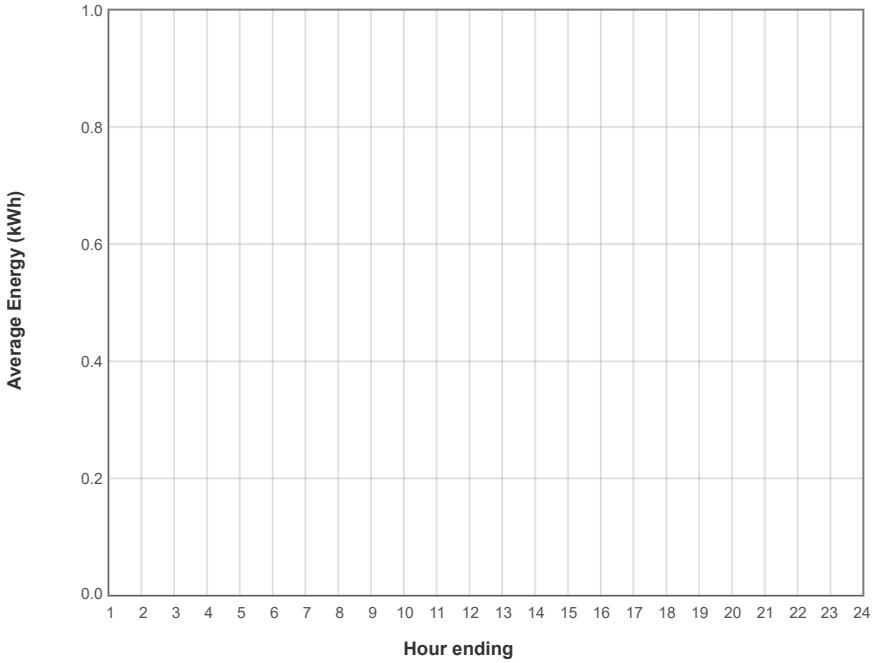
Add Load Shapes



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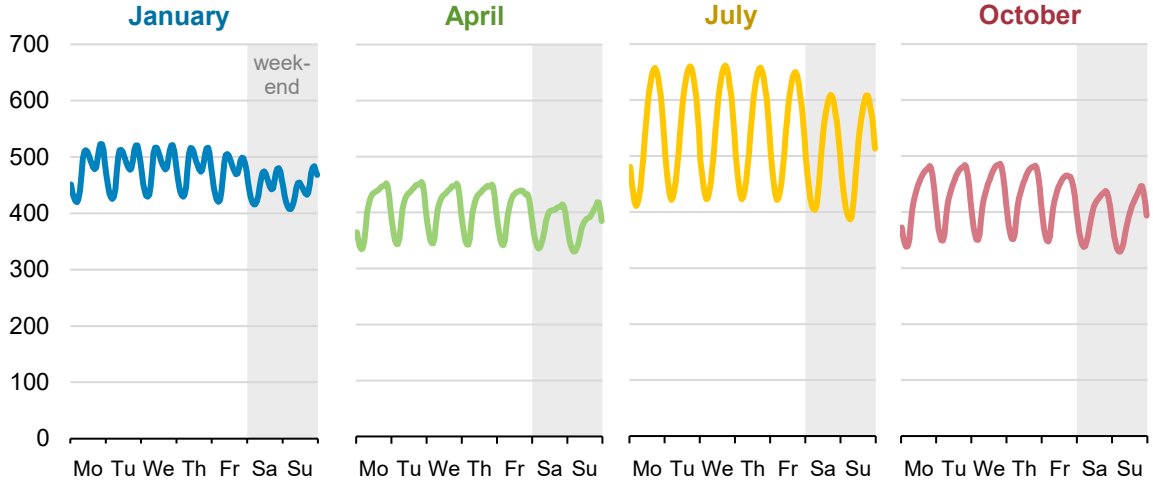
EIA will delay its scheduled data releases November 8-10, 2023, to complete a planned systems upgrade. We will continue collecting energy data from survey respondents and will resume our regular publishing schedule on November 13. See our latest press release for more details.

Today in Energy

February 21, 2020

Hourly electricity consumption varies throughout the day and across seasons

Average hourly U.S. electricity load during typical week, selected months
million kilowatthours



Source: U.S. Energy Information Administration, *U.S. Hourly Electric Grid Monitor*
Note: Data shown represent the average aggregate U.S. hourly load (Eastern Standard Time) by day of the week for the months indicated between 2015 and 2019.

The electricity consumed in a given period (often referred to as electricity load) varies throughout the year in somewhat predictable patterns. Total U.S. hourly electricity load is generally highest in the summer months when demand peaks in the afternoon as households and businesses are using air conditioning on hot days. During the winter months, hourly electricity load is less variable but peaks in both the morning and the evening. Load is generally lowest in the spring and autumn when homes and businesses have less need for space heating or cooling.

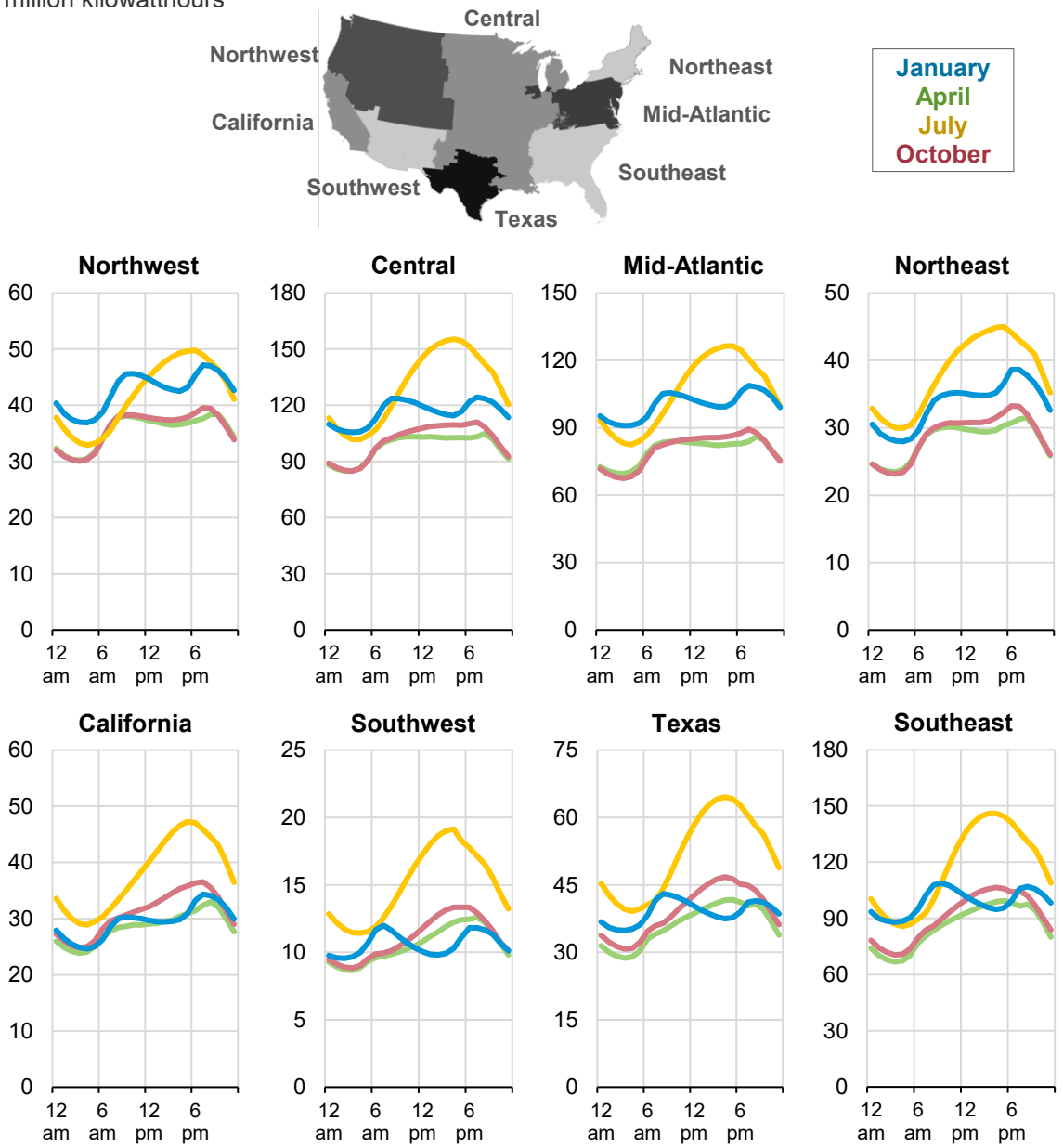
The U.S. Energy Information Administration (EIA) has been collecting near-real-time data on hourly electricity load for all of the balancing authorities in the Lower 48 states since 2015. These data are published on EIA's *U.S. Hourly Electric Grid Monitor* and are also available for aggregated regions and for the continental United States.

Nearly all U.S. households use electricity in some form. In 2015, about 25% of homes nationwide used electricity for all their energy needs, including cooking, space heating, space cooling, and water heating. On a daily basis, electricity usage in a typical home follows the daily habits of its residents. The least amount of electricity is consumed at night when most people sleep. The generally constant amount of electricity demand is called baseload, which covers the energy used for appliances such as refrigerators and other electrical devices that run continuously.

U.S. electricity consumption is generally lower on weekends and holidays than it is during the weekdays because many commercial offices are closed and less electricity is required for lighting and computer equipment. Although some utilities' definitions vary, the electricity industry places usage periods into two categories: on-peak hours that generally refer to the hours beginning at 7:00 a.m. until 11:00 p.m. on weekdays, and off-peak hours that are between 11:00 p.m. and 7:00 a.m. on weekdays and all day on Saturdays, Sundays, and holidays.

Electricity consumption typically cycles each day with the lowest demand occurring around 5:00 a.m., a rise in demand occurring at some point during the day (depending on the season), before falling back down during late evening hours. This variation in electricity demand follows the daily patterns of energy use by households and businesses, but it is especially dependent on weather-related factors. The overall level and shape of total U.S. electricity load varies from year to year, and typical load shapes vary across regions because of differences in weather patterns and the types of electrical equipment in use.

Average hourly electricity load during typical day by region, selected months
million kilowatthours



Source: U.S. Energy Information Administration, *U.S. Hourly Electric Grid Monitor*
Note: Hourly load shown is displayed for each region's local time zone.

During the winter, the daily cycle of U.S. total electricity load usually has a morning peak and an evening peak. Although the most common primary energy source for space heating is natural gas, about one-third of U.S. households primarily rely on electric furnaces or heat pumps. During the morning hours, electricity use rises as people turn on lights, turn up thermostats, and use hot water as they get ready for the day and as businesses and offices open. Electricity load ramps up again in the winter evenings as people return home and begin warming up their homes and cooking their meals.

Air-conditioning equipment is used in 87% of homes in the United States. During the middle of summer, air conditioning accounts for a large portion of residential and commercial electricity usage. The daily U.S. load cycle in the summer has a much wider range than in the winter because of the widespread use of air conditioning. Electricity consumption in the summer increases rapidly through the day along with temperature, reaching its maximum around 5:00 p.m. or 6:00 p.m. Average U.S. hourly electricity load peaks during the summer.

Principal contributor: Tyler Hodge

Residential End-use Electricity Demand: Implications for Real Time Pricing in Sweden

Author(s): Manias Vesterberg and Chandra Kiran B. Krishnamurthy

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Residential End-use Electricity Demand: Implications for Real Time Pricing in Sweden

Mattias Vesterberg and Chandra Kiran B. Krishnamurthy***

ABSTRACT

Using a unique and highly detailed data set on energy consumption at the appliance-level for 200 Swedish households, seemingly unrelated regression (SUR)-based end-use specific load curves are estimated. The estimated load curves are then used to explore possible restrictions on load shifting (e.g. the office hours schedule) as well as the cost implications of different load shift patterns. The cost implications of shifting load from "expensive" to "cheap" hours, using the Nord pool spot prices as a proxy for a dynamic price, are computed to be very small; roughly 2–4% reduction in total daily cost from shifting load up to five hours ahead, indicating small incentives for households (and retailers) to adopt dynamic pricing of electricity.

Keywords: Direct Metering, Residential Electricity Demand, Real time electricity pricing

http://dx.doi.org/10.5547/01956574.37.4.mves

1. INTRODUCTION

Driven by concerns involving, among others, capacity (and investment) constraints, environmental issues, and the need to balance intermittent renewable generation, there has been a renewed policy interest across the world in the efficient pricing of electricity. Given the specificities of the electricity market, the wholesale price of electricity varies substantially over the day; nonetheless, consumers have long been charged a fixed retail price. There is a long literature in economics arguing that the use of a price that better reflects the true cost of producing electricity on a more dynamic basis (e.g. an hourly price) will in theory give rise to substantial efficiency gains,[1] and a variety of "dynamic" or "real time" pricing (RTP) schemes have been proposed (but rarely implemented). These efficiency gains arise largely from a more efficient allocation of consumption, leading to a reduction in the need for costly peak capacity. Further, price-driven demand flexibility also has the potential to balance the variability of increased intermittent production, most notably wind and solar power, and to reduce congestion of transmission networks in Sweden.

Empirical evidence for the practicability of RTP schemes, and in particular the possibilities and incentives for households to respond to such pricing by shifting load from "expensive" to

1. The literature on efficient pricing of electricity is vast; see, among the more recent studies, a survey in Faruqui and Sergici (2010), the study of Allcott (2011) (and references therein), and a slightly older review in Aubin et al. (1995). The readers are also directed to some of the simulation-based studies cited in Section 2, including Borenstein and Holland (2005), Borenstein (2005) and Kopsangas-Savolainen and Svento (2012), among others.

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"cheap" hours, is, however, rather scarce. Indeed, as documented in Faruqui and Sergici (2010), the evidence is relatively mixed and depends upon a variety of factors. In general, the lack of relatively large samples of households on RTP schemes hampers evaluation of the demand shift actually realized. Given that data on household behavior under RTP is scarce, one way of empirically exploring the efficacy of RTP would be to compare the timing of current within-day electricity consumption (by households on non-dynamic-price contracts) with possible restrictions on substitutability, such as working hours and temperature variation.

These explorations are most useful with data at the appliance or end-use level, since substitutability will vary between appliances and end-uses; to illustrate, it might be easier to shift laundry within a day than to shift lighting, since the use of lighting is to a large extent determined by available daylight. Further, estimates of current within-day consumption are necessary as a baseline for computing the cost savings of re-allocating load. Unfortunately, the data required for such analyses are rarely available and only a few studies (e.g., Bartels and Fiebig (1990, 2000); Larsen and Nesbakken (2004); Allcott (2011)) in the very large literature in economics on electricity demand have been able to illustrate how residential electricity end-use consumption varies within a day and how this information could be used for policy analysis, e.g. to understand substitution possibilities. Our analysis adds to this sparse literature, and considers the case of Sweden. Sweden introduced a law allowing consumers to have access to RTP, in the sense that consumers can choose to have hourly price contracts without having to pay for the necessary metering equipment (source: §3 Chap 11 in the the electricity act).[2] Sweden is, to our knowledge, among the few countries to have had such an explicit and country-wide possibility for RTP.

Our study contributes to the existing literature in two ways. First, using a unique, appliance-level direct metering data set, we are able to provide estimates of conditional load curves and understand the implications for substitutability of load across hours, a maintained assumption in the theoretical (and many empirical) studies estimating the benefits from RTP. Second, using the estimated load curves and wholesale price data, we are able to provide (an approximation to) estimates of the benefits to the consumers from such load shifts. Our analysis, thus, is able to shed light on the extent to which various demand management strategies, particularly RTP, are likely to be effective. We note that, to our knowledge, ours is the first study providing such estimates for Sweden, and the results of our study should be of considerable relevance for Swedish energy policy, given the Swedish government's strong thrust on RTP.

In more detail, our analysis uses data from a study commissioned by the Swedish Energy Agency, which metered household electricity consumption at the appliance-level at ten-minute intervals for 389 households, none of which were on RTP contracts. Data at this level of detail have rarely been available for most countries. The appliance-specific nature of the metered data we use provides a unique opportunity to obtain better understanding of appliance- and end-use-specific consumption patterns. Prior approaches to estimating appliance- (or end-use-) specific load curves used the method of Conditional Demand Analysis (CDA), which suffered from many limitations, or a combination of metered data and CDA approaches. Aggregating the ten-minute consumption data to hourly, we estimate end-use specific load curves (conditional on household characteristics) and analyze how these correlate to possible restrictions on substitutability of load within the day. That is, we do not explicitly explore substitutability of load, but rather analyze possible *restrictions* on substitutability. These restrictions, including working hours, outside temperature and (lack of) daylight might—independently of the type of contract the household has chosen—impose significant limitations on any short-run attempt to shift load from "expensive" to "cheap" hours.

2. https://www.riksdagen.se/sv/Dokument-Lagar/Lagar/Svenskforfattningssamling/Ellag-1997857_sfs-1997-857/http://www.riksdagen.se.

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Finally, using the estimated load curves as the baseline, we examine the monetary incentives for households to shift load under an hourly pricing scheme based on average and maximum Nord pool spot prices, for average working days in February. The results presented here have important implications for Swedish energy policy, and in particular for the Swedish government's stated goal of implementing RTP. The success of this pricing scheme depends heavily on demand response which, our results indicate, are likely to be small, absent substantial investments in new technology and a focus on it from the retailers. Both consumers and retailers appear to have little to gain from a potential switch to RTP—at least in the short run—based upon our simple cost shifting experiments.

The rest of this paper is structured as follows. A review of the different strands of literature relevant for our analyses is provided in Section 2 followed, in Section 3, by a brief description of the Swedish electricity market. Section 4 provides a description of the data used in this paper, together with a few summary statistics on key variables used in the analysis. Section 5 details the estimation of the load curves, along with computations of the cost of servicing different end-uses and cost changes due to load shifts. Section 6 provides a discussion of the policy context of our analysis and concludes. Load curves for the month of June and details regarding the goodness-of-fit measures for the Seemingly Unrelated Regression (SUR) system used for our estimation are relegated to Appendices 6.1 and 6.2, respectively.

2. RELATED LITERATURE

We turn now to a brief review of the literature on within-day and end-use-level electricity consumption. As emphasized earlier, a clear understanding of both price responsiveness and baseline consumption patterns are key inputs to any analysis of policies concerning dynamic pricing. In particular, the success of RTP depends upon consumers responding to hourly price variation by re-allocating consumption within a given day.[3] However, as already noted, the literature on sub-annual appliance-level electricity demand—necessary for such analysis—is sparse, and especially rare are studies using hourly data. The CDA approach pioneered in Parti and Parti (1980) and refined in Bartels and Fiebig (1990, 2000); Fiebig et al. (1991) has been used as a way of overcoming the lack of appliance- (end-use-) level data. The idea in this approach is to combine data on total load with survey information on appliance holdings to estimate the contribution of each appliance to total load, exploiting heterogeneity in household appliance portfolio. The estimated coefficients, interpretable as the the mean contribution of each appliance to total load, are then used to produce daily load curves for selected appliances.

An obvious disadvantage of this method is an inability to estimate the load of appliances with high penetration rates such as TV, washing machine and lighting. Bartels and Fiebig (2000) partly overcome this drawback by combining survey data with real-time metering data, using a random coefficient model to allow for variation in appliance size and intensity of utilization between households. The mean response associated with each appliance is then estimated using data from both types of households, those that were, and those that were not, directly metered. See also Hsiao et al. (1995) for a bayesian approach on combining metering data with conditional demand analysis. Larsen and Nesbakken (2004) compare the CDA approach with an engineering model, ERAD,

3. Energy conservation is not the main policy goal of RTP. Further, households are, arguably, likely to be less enthused by energy conservation than by re-allocation of consumption over time, which is also the main idea of RTP (reducing costs while not having to reduce total consumption). However, it might very well be the case that increased feedback through hourly electricity prices also will lead to energy conservation for Sweden (see e.g. Energimarknadsinspektionen (2010)).

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whose inputs include engineering knowledge regarding technical and other features of housing stock, enabling estimation of energy demand for space heating. They compare the numerical results from these two approaches and provide a few recommendations regarding choice of end-use and what questions to implement in household surveys designed to disaggregate electricity consumption.

Before elaborating on how understanding within-day electricity consumption can assist in evaluating the scope for dynamic pricing, we briefly review some of the relevant literature on efficiency gains from RTP. We note that this literature is directly relevant for our analysis since substitution pattern across hours—the key aspect of our analysis—directly affects efficiency gains from RTP. A key aspect of RTP is that the benefits ("welfare gains") are typically obtained from a more efficient allocation of consumption, with consumption shifted from "expensive" to "cheap" hours, where "expensive" and "cheap" refer to system cost or spot market price. This then translates (in the long run) into re-allocation in capacity, with reductions in costly peak and mid-merit capacity. Naturally, the magnitude of the resulting welfare gains depend upon the actual generation technology mix. These aspects are explored in several simulation-based studies.

Borenstein and Holland (2005) and Borenstein (2005), in the context of the U.S., simulate the long-run effects of residential RTP and find significant increase in consumer surplus (3–11%). The efficiency gains arise from reductions in capacity (both peak- and mid-merit capacity are reduced in favor of baseload) and not just from reduced generation, as in the short run, and with a very low price elasticity (of -0.025)). Kopsangas-Savolainen and Svento (2012) reproduce these simulations for a Nordic market setting, imposing capacity restrictions on nuclear and hydro power (reflecting the limited scope for hydro and nuclear capacity expansion), and find that RTP reduces the need for peak and mid-merit capacity. As a further illustration, Holland and Mansur (2006) simulate the short-run effects of RTP, and find significant reduction in peak generation, but an overall increase in total generation for the U.S., with only a very modest (0.24%) welfare gain resulting from this re-allocation.

In the context of Sweden, the Swedish Energy Market Inspectorate ("energimarknadsinspektionen", EI), in a cost-benefit analysis of introduction of RTP in Sweden, estimates the social benefits to be substantial (varying between 1541 and 1989 million SEK, depending upon the share of households on RTP)[4] and advocates introduction of RTP in Sweden, either on a voluntary or mandatory basis (Energimarknadsinspektionen, 2010). In the EI report it is assumed that a substantial share (40 percent) of all households will be on real time pricing by 2030, or roughly 60,000 new RTP contracts per year.[5] However, the EI reports that during the first years of the RTP program in Sweden only about 8,600 households had adopted this new pricing scheme (Energimarknadsinspektionen (2014b)).[6] Further, as detailed in Section 3, demand flexibility might also play an increasingly important role in balancing the variability of wind power generation on a within-day basis. Hence, households will ideally not only respond to extreme price spikes but also to smaller but more frequent price variation (see Fritz et al. (2013)). Although there are technical issues to be

4. The benefits largely arise from replacing peak capacity; specifically, the alternative cost of the peak capacity (defined as capacity used less than 40 hours per year) is estimated at about 5 SEK/kWh (roughly 0.56 /kWh).

5. This estimate is partly based on the idea that Swedish residential consumers in general are rather active on the electricity market. For example, between 2005 and 2010 the number of variable-price contracts (contracts with prices varying over months, as compared to longer-term contracts) has increased (from zero) to 30 percent of all contracts, indicating that many consumers are interested in flexible types of contracts.

6. One explanation for this rather low figure is that as of spring 2014, only 68 (out of roughly 120) electricity retailers provided RTP contracts (according to a survey by the EI), and of these only a few had hourly prices on display (see Energimarknadsinspektionen (2014b)). Most RTP contracts required the household to call the supplier for the current price information. This indicates that the incentives for the retailers to promote RTP are limited.

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solved, the potential for using demand flexibility as an alternative to balancing generation is considered to be substantial.[7]

In many countries, transmission capacity is a key constraint; this is particularly the case in Sweden which has been divided into four price areas (see Section 3). With a sizeable fraction of Swedish households responding to RTP by reducing peak demand, congestion is likely to ease in the key transmission lines. This, evidently, is likely to lead to reduced prices for consumers, in particular in the two southern-most price areas in Sweden—where prices are in general higher than in the Northern regions. To summarize, in the medium-term, if an increasing fraction of Swedish households adopt RTP and respond as anticipated, welfare is likely enhanced, even if the realized benefits vary substantially across individuals and regions. This is particularly likely to be important in the future with the projected sizeable increase in generation from wind power. We note that both Borenstein (2005) and Kopsangas-Savolainen and Svento (2012) in their simulations assume unrestricted transmission capacity, although they briefly discuss implications of this assumption.

An important point to note is that all of the simulation-based studies cited above use a constant-elasticity hourly demand function, essentially assuming that household response to a price change is independent of time of the day and, further, that there is at least some substitutability between hours.[8] The dependence of welfare computations upon assumptions regarding consumer willingness, and ability, to shift consumption across hours provides a strong motivation for understanding current consumption behavior across hours. The key results of these simulation-based approaches, of some slight increase in total demand—indicating that consumers shift load from peak hours to off-peak hours–, can then be explained by this assumption. However, one of the few recent empirical studies evaluating an actual RTP scheme in Chicago, Allcott (2011), finds that the RTP scheme considered there does not lead to load shifting. Rather, the response to the pricing scheme is by energy conservation through reduction in load during peak hours, but with no increase in consumption during off-peak hours, contrary to results of the simulation that indicate a slight increase in total consumption.

Further, Allcott (2011) notes that even if households on RTP are fairly price elastic, the gains are rather small; the estimated increase in consumer surplus amounts to about $10 per year or approximately two percent of annual household electricity expenditure. In fact, Allcott goes as far as suggesting that even if residential RTP might be a theoretically sound idea, it might "provide an important real-world example of situation where this is not currently welfare-enhancing" (p.839). The very small benefits of, and therefore incentives to adopt, RTP for any individual household might imply that consumers are less likely to respond to RTP in the hypothesized way— by shifting load from peak to off-peak. There might also be reason to believe that there are short-run restrictions on the households possibility to respond, further strengthening this effect. For example, working hours, outside temperature etc. might impose restrictions on the substitutability of load within a given day, the combination of which can explain the results in Allcott (2011).[9,10]

7. Fritz et al. (2013) emphasize the need for sufficient monetary incentives to compensate households for loss of comfort, and point out that the current relatively small intra-day price variation will likely not yield sufficient potential cost savings for households.

8. If demand was completely inelastic for all hours, households would not shift any load at all.

9. Borenstein (2005) briefly discusses these issues in his sensitivity analysis, where he allow elasticity to vary with the demand level, first with elasticity increasing in demand levels and subsequently the opposite. For the latter case, he finds that the efficiency gains are "much smaller than in the case in which demand is more elastic at peak times" and also smaller than with constant elasticity (p.14).

10. Interestingly, in a recent study, Jessoe and Rapson (2014) report little to no load reduction or shift for the simplest RTP scheme, a time-of-use tariff, for commercial and industrial users, also implying virtually no welfare effect of RTP.

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There is some experimental literature on how households respond to dynamic pricing schemes in Sweden. For example, in a small-scale experiment, Swedish Elforsk Market Design and a few local retailers in southern Sweden[11] analyze the short-run household response to staged price spikes in the interval of 3 to 10 SEK/kWh (Lindskoug (2006)). The resulting load reduction was found to be rather large, up to 50% at hours with price spikes, with households using mixed heating (i.e. electric heating combined with other sources of heating, for example wood stove) succeeding in reducing total load the most. Given that such large price spikes are very unusual in Sweden (see e.g. Hellström et al. (2012) and the Nord pool February spot price in Figure 6), it is not clear how relevant these results are for more moderate (and frequent) price variations typically considered in dynamic pricing analyses. Factors such as the magnitude of the price shocks and the fact that households self-selected into these experiments render the external validity of these findings questionable.

To summarize, the key points of the literature regarding RTP are that, while simulation results—assuming low-to-moderate but fixed-across-hours price elasticity—indicate modest welfare gains from RTP (along with moderate increase in total load), the limited empirical evidence accumulated indicates minimal welfare gains from RTP (along with possible energy conservation). In particular, for Sweden, projections of voluntary adoption rates of RTP, based on limited evidence, appear rather optimistic. Further, a major determinant of the magnitude of welfare gains from RTP is the (generally assumed) elasticity of substitution across hours, an exploration of which is the goal of our analysis.

3. THE SWEDISH ELECTRICITY MARKET

The deregulation of the hitherto highly regulated Swedish electricity market in 1996, following the example of other European countries, introduced competition between electricity supplying companies, with distribution a state monopoly. This period also marked the beginning of market integration with the other Nordic countries (Finland, Norway, Denmark) and the Baltic states via a common spot market, the "Nord Pool Spot". Following this deregulation, market price today is determined by demand and supply on the Nord Pool power exchange, located in Oslo, Norway. The day-ahead market, Elspot, is the main venue for trading electricity in the Nordic region, with 75% of total electric supply in the Nordic countries traded here. Contracts are concluded between approximately 370 sellers and buyers for delivery of power the following day, and market price is determined based upon the supply and demand of electricity on that day. Further, there exists an intra-day maket, Elbas, to cover potential imbalances occuring between the closing of Elspot at noon and delivery the next day. In 2014, maximum system price was 1.45 SEK/kWh (in December) and average price was 0.27 SEK/kWh.[12]

The bulk of electricity produced in Sweden is from hydro and nuclear sources, constituting 45 and 43 percent of total production, respectively (figures for 2014, from SvK). The remaining production is from thermal (co-generation) plants and windpower, together with some smaller sources of peak capacity.[13] This peak capacity, loosely defined (following e.g. Kopsangas-Savolai-

11. Skånsk Energi and Vallentuna Energi were the two local utilities involved in the experiment. Elforsk is a Swedish electricity research institute financed by the Swedish electricity industry and the Swedish Transmission System Operator (TSO), Svenska Kraftnät (SvK).

12. 1 SEK (Swedish Krona) was approximately 0.12€ or 0.15$ in Feb 2014. Source: http://www.svenskenergi.se/Global/Statistik/El%C3%A5ret/Sv%20Energi_el%C3%A5ret2013_versJUNI2014.pdfhttp://www.svenskenergi.se.

13. Shortages and blackouts are not an issue in Sweden due to large (surplus) capacity in hydro-power; peak capacity is therefore relatively small.

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nen and Svento (2012)) to be the technology with the highest marginal cost (and hence least utilization), consists of gas turbines and oil fired condensing power plants, with approximately 3,000 MW of installed capacity.[14] It is anticipated that the reserve capacity needed will likely increase in the future due to substantial expansion of intermittent (e.g. wind power) generation in Sweden (Energimarknadsinspektionen (2010)). Currently, hydro power is used in Sweden both as baseload and as balancing load (to balance the variability of wind power generation, in particular). However, there is an ongoing debate on whether hydro power alone will be sufficient in balancing the (anticipated and on-going) expansion of wind power generation. Here, demand flexibility could play an important role in providing alternative means of balancing system load, as emphazied by Elforsk (Fritz et al. (2013)).

From the 1st of November 2011, Sweden has been divided into four price areas to reflect structural restrictions in transmission capacity. As most electricity production is located in the north of Sweden while most demand is in the southern part, prices are typically higher in the two southern price areas. Further, there have also been price differentials during periods typically associated with low demand, which have been attributed to production or transmission malfunction and hence are not associated with high electricity usage (Energimarknadsinspektionen (2014a)).

Turning to the demand side, Sweden has a very high—among the ten highest—electricity intensity per capita, at roughly 14,000 kWh for 2014.[15] This is explained both by the cold and long winters and an energy intensive industry. The residential sector accounts for roughly 23 percent of total consumption. Disaggregated information about residential demand is sparse, but Statistics Sweden assumes that a "representative" household with electric heating consumes approximately 20,000 kWh per year. As of 2013, about 40 percent of all households were on fixed rate contracts with yearly or longer contract durations while about 30 percent were on variable rate contracts. The general trend is that households are switching from so-called default contracts to variable rate contracts.[16] For the previous nine years (2005–2014), the average fixed rate price was 0.49 SEK/kWh while the variable contract price was 0.45 SEK/kWh (with a variance of 0.019 SEK/kWh).

Concerning energy and climate policy, Sweden has set out rather ambitious climate policy targets following the EU Climate and Energy Package (the 20-20-20 target), stipulating, among other things, 20 percent increase in energy efficiency and 50 percent share of renewable sources in total energy consumption by 2020 (relative to 2009). The Swedish Energy Agency has been commissioned by the Swedish government to both detail what this target implies for Sweden (concerning the specific energy efficiency target over the stipulated period) and to present a plan of how to reach the target. It is argued that a Swedish implementation of real time pricing, and a more efficient energy market in general, will assist in reaching this goal (see e.g. Energimarknadsinspektionen (2010)).

14. SvK is responsible for managing the balancing capacity and strategic reserve, and can procure up to 1500 MW in peak capacity (from Swedish producers). Note however that generation from these technologies is quite small, and during the last ten years production has varied between 0.2 and 1.5 percent (300–2000 GWh) of total annual production (http://www.scb.se/Pages/TableAndChart____24270.aspxhttp://www.scb.se/Pages/TableAndChart____24270.aspx). The Swedish Parliament has decreed that the capacity reserve shall be phased out by 15 March 2020 and replaced by market-driven capacity and/or demand flexibility.

15. Source: http://www.svenskenergi.se/Elfakta/Elanvandning/.

16. All households have the opportunity to choose a preferred contract type and energy provider ("retailer"); those households which do not make an active choice are assigned a default contract where prices typically are fixed on an annual basis.

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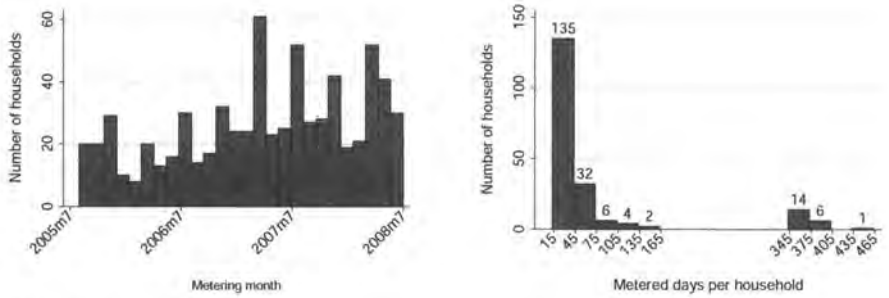
Figure 1: Distribution of Metered Data



(a) Monthly household metering
Metering began in August 2005 (2005m8) and ended in July 2008 (2008m7).

(b) Total metered days.
Days of metering do not correspond to a full calendar month.

4. DATA AND SUMMARY STATISTICS

The data used in this paper originate from a metering project commissioned by the Swedish Energy Agency between 2005 and 2008. The purpose of this project was to increase the quality of data on residential electricity consumption, and to assess the potiential for energy conservation and increasing energy efficiency. In total, 389 households, sampled by Statistics Sweden, had metering equipment installed on most major appliances. We provide a brief overview of the survey here, and refer the readers to the Energy Agency's report (Zimmermann (2009)) for more details. Roughly 150 different appliances were metered, with each household having a maximum of 46 appliances metered at a time. In addition, each household had individual meters recording both outdoor and indoor temperature; consumption and temperature data were recorded at ten-minute intervals. Two hundred of the homes metered were detached houses, and the remaining 189, flats. We focus exclusively on detached houses, since they have a substantially higher level of consumption and are typically more important in Sweden from a policy perspective.

A majority of the households were located in the Mälardalen region, with only 25 households each located in northern and southern Sweden.[17] The project was carried out between 2005 to 2008 and each household was metered for between 15 days and 16 months. Figures 1a and 1b illustrate the time distribution of metered households. Figure 1a illustrates the months (and years) households were metered in; as is evident, roughly 10–20 households per month were metered during 2005 and 2006, and 20–30 households per month during 2007 and early 2008. From Figure 1b, which illustrates how many days household were metered for, it is evident that a majority of the households were metered for one to three months, and a few households metered for three to six months, and fewer still for between 12 and 16 months.

In addition to the metering data, survey data was collected on household characteristics such as (monthly) income, number and age of inhabitants, living area size, main heating system,[18]

17. The Energy Agency is situated in Mälardalen, so convenience is a possible explanation for this geographical focus. Since this is a very small geographical region, the variation in temperature is likely small; however, variation in other household characteristics is substantial. We also note that the Energy Agency removed regional markers from the data set provided for use, precluding the inclusion of region fixed-effects to control for region-specific characteristics that are time-invariant. Overall, the rather narrow geographic spread of the sample tends to weaken the external validity of the quantitative results. Nonetheless, provided households in the rest of Sweden have patterns of behavior which are not very dissimilar, we anticipate the qualitative results to broadly hold.

18. We consider two main sources of space and water heating, electric and "mixed". In Sweden, households with electric heating primarily use water-based heating systems, thereby also precluding separation of the water- and space-

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Table 1: Summary Statistics for Detached Households by Month

	February	June		February	June
	Household Characteristics			**Monthly Load (kWh)**	
Household income (SEK)	39741.457	41523.138	Heating (incl. water heating)	569.775	156.390
	(9804.552)	(6841.511)		(579.307)	(135.979)
Household size (persons)	3.262	3.397	Kitchen	55.343	63.717
	(1.037)	(1.008)		(31.330)	(35.760)
Living area (m^2)	138.476	134.362	Lighting	54.029	24.054
	(25.282)	(29.944)		(35.260)	(18.725)
Building Year	1970.575	1971.614	Laundry	13.830	12.297
	(19.097)	(18.605)		(14.939)	(14.147)
Number of appliances	26.48276	26.40476	Electronic media	86.231	82.588
	(6.003629)	(4.80375)		(87.022)	(88.664)
			Total	779.208	339.046
Observations	42	58		42	58

Notes: Sample mean reported, with standard deviation in parenthesis, for the regression sample for respective month. Observations vary by month, for reasons already discussed in the text.

building year, and year of refurbishment. For some appliances, information on brand and model is also available. The lack of household level price and contract data precludes an analysis of price responsiveness, although it may be noted that price variation at the required frequency would not be available for most Swedish households.[19] Table 1 provides summary statistics for household characteristics for the two months whose load curves are computed, February and June, while Table 2 provides the summary statistics on the complete data set for detached households. Household income is reported in intervals, but following e.g. Stewart (1983) we use interval regression to generate a continuous income variable (our results do not change when the original income variable, in intervals, was used). Motivated by policy, which is broadly centered around end-use categories, we focus on five key end-uses into which the individual appliances are aggregated: space heating (including water heating), kitchen (all kitchen appliances), lighting, laundry (including dryers), and electronic media (mostly TV, AV equipment and gaming consoles).

We briefly consider the complete data summaries first, from the "All Heating systems" column of Table 2. Household size (number of persons) varies between 1 and 6, with a mean of 3.2, and living area (m^2) has a mean value of 136. Building year, which varies between 1926 and 2007, with a mean year of 1970, is expected to have a substantial effect on heating consumption, with old houses being expected to be more "leaky" and hence have higher heating load. Finally, between 10 and 46 appliances were metered for each household with a mean of 25, covering all main appliances.[20] We find only moderate differences in household characteristics between house-

heating components. The "mixed" heating category of households may be understood as those using primarily a non-electric heating source, typically district heating, along with supplementary sources of space heating on very cold days. For example a house which is connected to the central heating system (via district heating) might activate an electric heating system as a secondary source on colder days. This also helps explain observations of non-negative heating consumption for households which report "mixed heating" as their main space and water heating source.

19. In other words, interest centers on across-hour price elasticity, for estimating which hourly price variation would be required. Since most households in Sweden experience price variation at a monthly or annual time scale, it is not obvious how such price variation would be used to obtain information regarding hourly elasticity, the elasticity of interest in our case.

20. We note that no information is available in the survey regarding the criteria used to choose the number of appliances metered in each household. This also precludes the use of "number of appliances" as a control variable (since

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Table 2: Summary Statistics for Detached Households by Heating Source

	Mixed heating	Electric heating	All heating systems
Household characteristics			
Household income (SEK)	42310.31	40690.99	41284.99
	(6829.19)	(8049.76)	(7664.58)
Household size (persons)	3.479	3.104	3.263
	(1.067)	(1.147)	(1.129)
Living area (m^2)	139.56	134.23	136.4
	(49.63)	(28.59)	(38.6)
Building Year	1966.4	1970.9	1969.3
	(20.43)	(24.07)	(22.92)
Number of appliances	23.36	28.39	26.24
	(4.06)	(5.05)	(5.28)
Monthly consumption (kWh)			
Total	767.1	942.0	870.9
	(646.1)	(792.7)	(741.2)
Heating (incl. water heating)	382.2	613.9	519.8
	(541.9)	(625.7)	(603.5)
Kitchen	89.2	89.1	89.2
	(51.3)	(62.5)	(58.2)
Lighting	64.9	59.2	61.5
	(45.4)	(57.0)	(52.7)
Laundry	19.9	20.2	20.0
	(23.9)	(24.2)	(24.0)
Electronic media	143.9	96.4	115.7
	(187.7)	(74.7)	(134.6)
Observations	273	399	672

Notes: Sample mean reported, with standard deviation in parenthesis, for all detached households for all months. End-use and variable definitions are as in Table 1.

holds with different heating systems, with notable differences restricted to appliances (larger number of appliances metered for electrically-heated households) and income (slightly higher income for households with mixed heating). Overall, households with mixed heating tend to have slightly higher income, to be slightly larger in size (both in m^2 and number of inhabitants) and slightly older than electrically heated homes. Nonetheless, the differences between these two types of households are rather moderate. This feature motivates the relatively simple load curve estimation framework, with load curves for houses which are electrically heated differing from those on mixed heating by only an intercept; see Section 5. The monthly average for a household with electric heating corresponds to an annual load (multiplying the average monthly load by 12) of roughly 17,000 kWh, slightly less than the 20,000 kWh assumed by Statistics Sweden for the reference household, as already mentioned. Also evident from Table 2 is the substantial difference in load between households with different heating systems, in terms of both total and heating load. However, households are rather homogenous in terms of kitchen and lighting consumption, irrespective

the total load may not correspond to the actual number of appliances owned, while for specific end-use categories, the total number of appliance owned can provide little additional information after controlling for income and household- and home-size).

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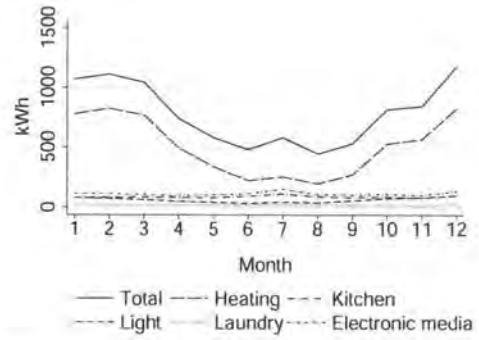
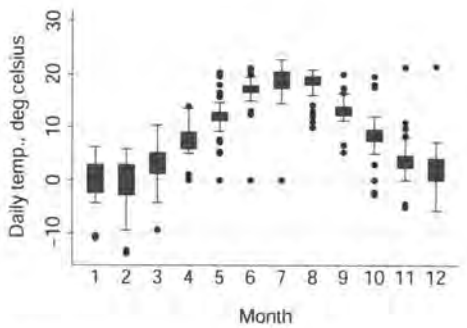
Figure 2: Monthly End-use Load and Outdoor Temperature



(a) Monthly electric consumption by end-use.



(b) Daily outdoor temperature by month.

of heating system. Naturally, residential electricity consumption is subject to seasonal variation; as is evident, during warm summer months even households with electric heating only have very small heating consumption. This seasonal pattern is illustrated in Figure 2a, where we present average monthly consumption by end-use over the studied period (2005–2008), from which a distinct winter peak, with more than the double the monthly summer load, is evident. As winters in Sweden are both dark and cold (see Figure 2b), this pattern is anticipated.

Noting that the number of households metered varies by month, we briefly consider whether households metered in February are substantially different from those metered in June. We note that (average) June load is slightly less than half that in February, primarily due to the much lower heating (less than a third) and lighting (less than half) load, a pattern that appears to follow those of temperature and daylight. Turning next to household characteristics, we note that only in terms of income do households metered in February differ substantially from those metered in June, with average household income in June about 2000 SEK (or 5%) larger. To summarize, load patterns for June and February are as anticipated based upon climatic patterns, while household characteristics do not differ sizeably, with more households—with slightly higher income—being metered in June. This similarity in household characteristics ensures that February load curves differ from those of June primarily in the pattern of usage, rather than in the type of households metered.

5. THE LOAD CURVES

5.1 Estimation Framework

For the load curve estimation we consider a subsample of the full data set, consisting of all working days in February (of all years) for detached homes only. Given that heating is the end-use with by far the largest load, the choice of February is motivated by the fact that this is usually the coldest month (see Figure 2b). We also compare the results from this month with consumption for working days in June, June being the warmest (non-vacation) month; these figures are presented in Section 7.1.

Following Bartels and Fiebig (1990, 2000), we also use a Seemingly Unrelated Regression (SUR) framework for estimation of the end-use load curves, conditional on household-specific characteristics, with a total of 24 hourly equations for each end-use. Note that conditioning on household-specific variables can serve many purposes, including allowing for a formal interpretation of the "average household", for counter-factual policy simulation (e.g. Bartels and Fiebig (1996)),

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and for providing a basis for understanding the determinants of hourly demand, including demand elasticities. Unlike in Bartels and Fiebig (2000), a majority of the appliances are metered in our sample and, as a result, there is no scope for combining metered and unmetered data. This considerably simplifies our estimation framework, which we present next.[21]

The actual equation estimated, for a given end-use and for hour t, is

$$\bar{Y}_{i,t} = b_t + \delta_t^y + \beta_t X_{i,t} + v_{i,t}, \; i = 1,2,\ldots,H, \tag{1}$$

where $\bar{Y}_{i,t} = \dfrac{\sum_{d=1}^{D} Y_{i,t}^d}{D}$ is the mean daily load for hour t and household $i = 1,\ldots,H$, with D the number of relevant days (e.g. 20 working days in February), $X_{i,t}$ are the control variables and δ_t^y denotes a year dummy accounting for year-specific effects (if any) on daily consumption (year indices are suppressed on X and Y).[22] In other words, one SUR system of equations are estimated for each of the K end-uses, where the equations correspond to hours and observations to (the average over February working days) household load for that hour. Essentially, this formulation allows us to focus on variability across households, and leads to an interpretation of equation (1) as modeling the consumption of household i on an *average* February day.[23] Thus, the percentiles of (predicted or actual) consumption, based upon equation (1), refer to those of the relevant household on an average February working day, an interpretation which facilitates our subsequent discussions regarding household behavior.

The main list of control variables for all end-uses are: living area (m^2), income (in SEK), and number of inhabitants. In addition, we include outdoor temperature, building year, and an indicator for electric heating for the heating end-use. The motivation for inclusion of the independent variables is as follows: as heating is by far the largest component of total load, outdoor temperature is expected to significantly affect electricity consumption; a similar argument can be made for the inclusion of building year and living area, as old (and presumably more leaky) houses, and larger houses, consume more electricity for space heating. Of course, whether the household has only

21. It is worth pointing out that the reason the framework in Bartels and Fiebig (2000) is relatively involved is the heteroscedasticity induced by the presence of non-metered appliances/end-uses. Since all end uses—and almost all appliances—are metered in our case, we can use the standard SUR framework with hours as equations (as pointed out in Bartels and Fiebig (2000, p.54)).

22. More formally, the SUR system above can be written in the usual form for the k^{th} end-use as

$$\mathbf{y}_t^k = \mathbf{X}_t \Gamma_t^k + \mathbf{v}_t^k, \tag{2}$$

where $\mathbf{y}_t^k = [\bar{Y}_{1,t}^k, \bar{Y}_{2,t}^k, \ldots, \bar{Y}_{H,t}^k]^T$ is a vector of size $H \times 1$, $\mathbf{X}_t$ is of size $H \times M_t$, with H the number of households (40 in our case) and M_t the number of covariates for the t^{th} hour, $\Gamma_t^k = [b_t^k, \delta_{y,t}^k, \beta_t^k]$, an $M_t \times 1$ vector of coefficients, and $t = 1,2,\ldots 24$ the number of equations.

23. An alternative approach would be to use the data from every day in February, which leads to the following equation for the t^{th} hour (with obvious notation):

$$Y_{i,d}^k = a^k + \alpha_i^k + \delta_y^k + \beta^k X_{i,d,t} + \epsilon_{i,d}^k.$$

This approach provides additional benefits in terms of accounting for individual-level "unobserved heterogeneity" (as is typical with "fixed effects") or any other cause leading to violation of the usual orthogonality conditions at the individual-equation level, due to the inclusion of the household "fixed effects", α_i. On the other hand, in our load curves below, the interpretation in terms of households (e.g. "median household on a average day in February") is more complicated, since there is variation across two dimensions, now; day and household. Nonetheless, the load curves obtained using this approach are qualitatively virtually identical to those obtained using the average data above, and so too are the cost implications explored in Section 5.3. These load curves and cost estimates are available upon request.

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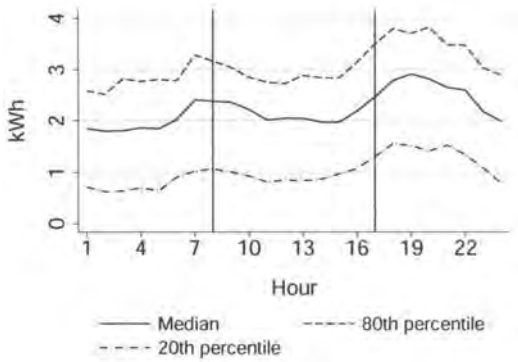
Figure 3: Total Consumption by Hour



Note: Typical working hours—assumed to be 8 AM to 5PM—are indicated by the vertical lines.

electric heating or mixed heating should also affect (heating) consumption. We also include number of inhabitants and income, as this is likely positively correlated with both the number of appliances possessed and their efficiency.

The SUR framework is motivated by the observation that it is very likely that unobserved determinants of household behavior are common to all hours and joint estimation across hours is likely to yield efficiency gains. In addition, the variation of outdoor temperature across hours (i.e. equations) implies that our SUR framework is not equivalent to equation-by-equation OLS (since one of the *X*s varies across equations). We estimate equation (1) and use the median predicted value to produce end-use specific load curves, noting that the median is used to ensure robustness to outlier observations (the use of the mean provided qualitatively similar load curves). In addition, we also produce load curves for the 20th and 80th percentile consumption (i.e. percentiles of $\hat{Y}_i$) to illustrate household heterogeneity in terms of hourly load. We define total load for hour t as the sum of the predicted values of the K end-uses in that hour, i.e. $\hat{Y}_{i,t}^{total} = \sum_{k}^{K}(\hat{Y}_{i,t}^{k})$.

5.2 Estimated Load Curves

We now turn to the estimation results, and note that the coefficients from the SUR system are not reported but are available upon request. The SUR framework set up above passes many standard goodness of fit tests (detailed in Section 7.2).

Total load is displayed in Figure 3, illustrating the median consumption together with the 20th and 80th percentile consumption. Note the rather large, and expected, difference between the median and the 20th and 80th percentile, driven to a large extent by differences in heating load. We elaborate more on this below, when we discuss the load curve for heating. As anticipated, there are two distinct and intuitive peaks, the first at approximately 6 am when the household wakes up and the second, at about 5 pm when the household returns home from work. It is clear that the two peaks correspond roughly to working hours (typically 8 am–5 pm in Sweden), illustrated by the two vertical lines.

In Figure 4a we display the estimated load curve for heating. Sizeable differences between households are evident, with the median heating load roughly three times the 20th percentile load. As noted above, this is mainly due to differences in heating systems. Households with mixed heating have the possibility to reduce electricity consumption substantially by substituting electric heating

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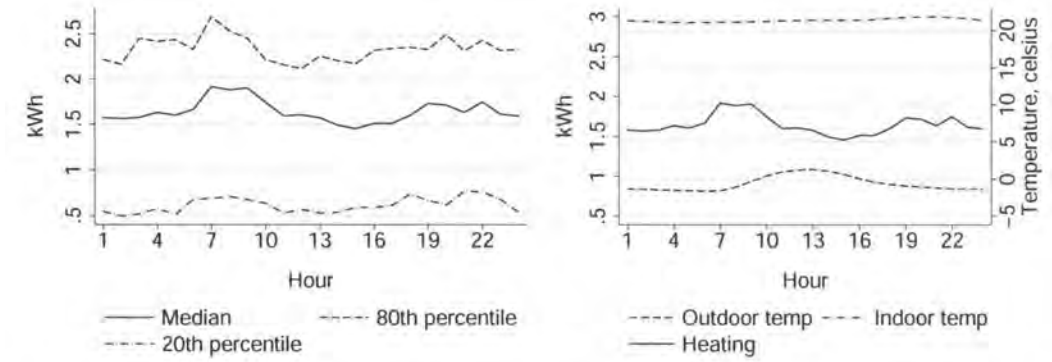
Figure 4: Heating Load Curves for an Average February Working Day



(a) (Median) Heating consumption by hour.

(b) Heating consumption with (metered) mean outdoor and indoor temperatures.

with, e.g., a wood stove or district heating. However, even if the 20th percentile consumption is relatively small compared to the median, it is nonetheless large compared to that of lighting or kitchen (roughly 0.5 kWh throughout the day, comparable in magnitude to peak lighting or kitchen load for the 80th percentile household, see Figure 5b and Figure 5a). Thus, the heating load curves not only illustrate household heterogeneity but also just how large the heating end-use is (in terms of kWh), relative to others. A distinct morning peak (and to a lesser extent an evening peak) for the heating load curve is also evident for all levels of consumption, although it is less pronounced for the 20th percentile.

In Figure 4b, we illustrate the median heating load together with the average (hourly) outdoor and indoor temperatures. The heating load curve appears, approximately, to be a mirror-image of outdoor temperature, as can be anticipated. Interestingly, although there is a decrease in heating load during the mid-day, this does not lead to a corresponding reduction in indoor temperature. As residents usually are away from home during mid-day (and therefore should not be concerned with a specific indoor temperature), this suggests that there is potential for energy conservation by reducing heating consumption without reducing the utility derived from it (i.e. without reducing indoor temperature during periods when householders are at home).

The load curve for lighting is displayed in Figure 5b. Here households appear to be rather homogenous in their consumption, with both the 80th and 20th percentile close to the median. There is a smaller peak during the morning, and a larger one between 4 pm and 10 pm, corresponding respectively to sunrise and the evening post-sunset period. Furthermore, lighting load is higher during the evening, likely since there are more activities at home during this time (compared to the morning). Also worth noting is the close-to-zero load late at night, implying only limited stand-by usage. Compared to the heating load, we note that lighting load is rather small in absolute terms.[24] The load curve for the kitchen end-use is displayed in Figure 5a. Households appear to be rather homogeneous in terms of kitchen electricity use as well, since the percentiles are close together. At first sight, it might also seem strange that there is no morning peak. However, Swedish breakfast

24. We observe that the metering campaign was commissioned before the EUs phase-out of incandescent bulbs in favour of more energy-efficient lights. This measure, we surmise, is likely to have led to a (parallel to the one here) shift of the lighting load curve downwards i.e. we anticipate that the shape of the load curve has remained roughly the same after this policy measure.

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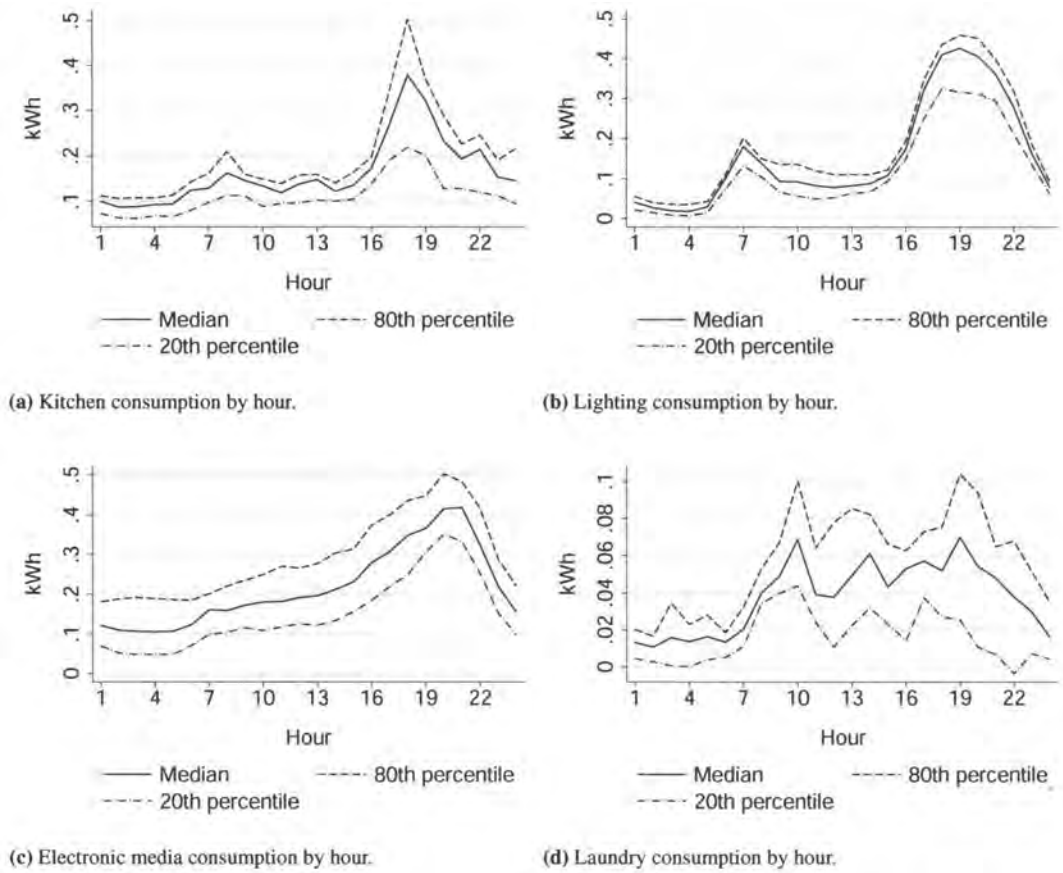
Figure 5: Load Curves for Kitchen, Lighting, Laundry and Electronic Media, for an Average February Working Day



(a) Kitchen consumption by hour.

(b) Lighting consumption by hour.

(c) Electronic media consumption by hour.

(d) Laundry consumption by hour.

is by tradition cold, and even if some electricity is used for making coffee etc. this load is small compared to the more cooking-intensive dinner. There is a distinct dinner peak between 4 pm and 8 pm, as anticipated. Clearly, some people end their working day early since the dinner peak starts at roughly 4 pm, one explanation being that some householders are retired or are working part time (this is the case for lighting as well). The magnitude of the kitchen load is comparable to that of lighting, and is rather small in comparison to heating.

The load curve for electronic media is presented in Figure 5c. Since this category contains many different appliances such as TV, computers, etc, it is difficult to interpret the shape. However, we note that this curve also has an evening peak, occurring roughly at the same time as the other end-uses. This peak is also intuitive; householders use AV equipment largely in the evening, after returning from work. The load curve for laundry is illustrated in Figure 5d. Laundry is typically used during day time, but the usage in terms of kWh is on average very small compared to other end-uses. Note that laundry is not subject to certain restrictions (daylight and outdoor temperature), suggesting possibilities of load shifting from e.g. weekdays to weekend (or other times when prices are expected to be lower). However, the fact that laundry is such a small part of total electricity usage during the weekdays (when RTP is likely to be in effect) suggests that the cost savings from shifting laundry are expected to be very small.

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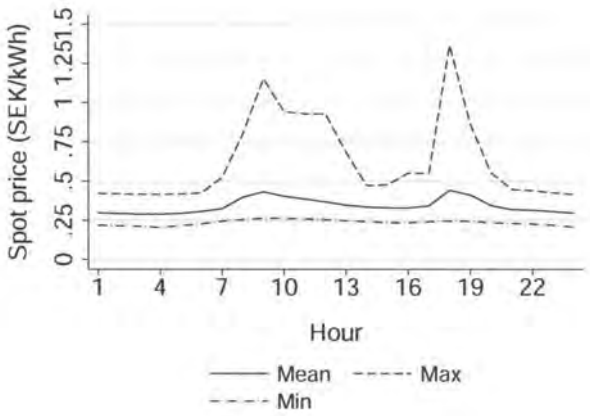
Figure 6: Hourly Nord Pool Spot Prices (price area three in Sweden) for February (2006–2008)



Finally, we note that the load curves illustrated here are for a given technology, and that advances in technology may alter the observed patterns in the load curve.

5.3 Cost Savings from Load Shifting

We turn now to computing the cost of servicing each end-use and to understanding how these would change if the average household shifted total load. From either the policy maker or the consumer perspective, this is a key factor to understand. Before turning to this task, however, we first briefly explore the patterns in the Nord pool spot price upon which our cost shift analyses are based. Note that we only consider the spot price for working days in February and also that the price is applicable for all demand, not just residential. In that sense, the price curve not only shows the scope for price-induced load shifts but also gives a picture of the system peak. Finally, we observe that the Nord pool spot price, as the wholesale price, is likely to form a base for retail price in any dynamic pricing scheme.

It is important, at this juncture, to note that the Nord pool spot market is a regional market, with prices varying across regions of Sweden (and Norway), as already discussed. This implies that despite the relatively small size of the Swedish residential sector, and the presence of three other countries, on the Nord pool market, large-scale adoption of RTP by Swedish households can lead to non-trivial changes in the (often sizeable) regional price differentials across different price regions of Sweden. Exploration of such differences, naturally, will need a model of the Nordic electricity system with transmission constraints, and is beyond the scope of our empirical analysis of the demand side. In light of these considerations, our analysis, which uses the Nord pool spot price as an "equilibrium price", is intended to provide a first approximation to a counter-factual scenario of RTP, in common with most empirical studies of the effects of RTP.

Turning now to the Nord Pool spot price, two price peaks are evident from Figure 6, in which the mean, minimum and maximum hourly spot prices are plotted; one at roughly 9am and another at about 5pm, with maximum price peak being more pronounced. Comparing the spot price to the estimated load curves, it is evident that these two price peaks coincide with the household demand peak. Further, when residential demand is low during the early morning, and late at night, the system price is also rather low. This consumption pattern has two important implications: first, it is in line with the hypothesized behavior of "excessive" consumption during periods of high

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(system/spot) price and second, it indicates that there are potential cost savings from shifting consumption to off-peak hours. However, as the variation in the average spot price is rather small, the potential cost savings are a priori expected to be limited, on average.

To estimate the cost of servicing each end-use, we match the estimated load curves with the corresponding spot prices, using the average/maximum spot price (over 2005–2008) for working days in February (see equations 3 and 4). Since we use spot prices rather than retail prices, these costs could either be interpreted as the retailer's cost, or as a proxy for household cost when on RTP.[25] Further, the EI estimates that roughly half of the variation in wholesale prices translates to variation in retail prices (Energimarknadsinspektionen (2006)). This then implies that the price curve for RTP contracts is flatter than that of the corresponding spot price. We denote the mean spot price for hour t by $\bar{p}_t$ and the predicted hourly load for end-use k as $\hat{Y}_k^t$. To obtain the cost C_k^t of servicing end-use k in hour t, we simply multiply the predicted hourly load with the mean spot price for that hour:

$$C_k^t = \hat{Y}_k^t \bar{p}_t, t = 1, \ldots, 24, k = 1, \ldots, 4. \tag{3}$$

The daily cost of servicing end-use k is then the sum of the 24 hourly costs,

$$C_k^d = \sum_{t=1}^{24} \hat{Y}_k^t \bar{p}_t = \sum_{t=1}^{24} C_k^t, \tag{4}$$

computed separately for the median and the 20th and 80th percentiles. The total daily cost is defined as the sum of the daily end-use specific costs.

Table 3 illustrates the cost of servicing each end-use for the median household during an average February working day. Evidently, heating is by far the most expensive end-use, being the largest load. For the other end-uses, even if the timing of demand (being part of peak demand) coincides with high spot prices, cost is nonetheless small relative to the cost of heating.

We turn next to evaluating how these costs change when we shift a particular end-use load from expensive to cheap hours; the interpretation of cost changes is as before. The conceptually most simple way of shifting the load curve is to move the whole curve a few hours ahead in time, while keeping the shape of the load curve intact, similar to the approach used in Bartels and Fiebig (2000) (although they only shift the load for one appliance; pool pump).[26] We shift the total load curve in this way one to five hours ahead and compute the cost change in percentage of daily total costs. When load is shifted five hours ahead, the demand peaks occur at hours with low system price. Note that by doing this we keep the total daily load constant, and are only re-allocating consumption across hours, consistent with the constant-elasticity-across-hours assumptions in evaluations of RTP benefits in Borenstein (2005); Kopsangas-Savolainen and Svento (2012).

We carry out this experiment for the median household, using average spot price, but test how the cost changes differ for households at the 80th and 20th percentile of consumption, as well

25. It is a proxy since the households also pay taxes, transmission fees and a mark up. Note however, that, except for the VAT, other fees tend to be fixed costs. A 25% VAT is charged on the total electricity price, including transmission fees. We choose to ignore this cost in the calculations, but note that the calculated cost savings below, for this reason, are slightly downward biased. However, this should not substantively affect the qualitative results of our experiment.

26. Note that we only carry out this experiment for within-day load shifting, not for across-day shifting. For all of these end-uses except for laundry, the substitutability of load across days (for example from a working day to the weekend) is limited. For example, it would not make any sense to shift space heating or lighting from one day to another, since that would imply one very cold and dark, albeit cheap, day.

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Table 3: Daily Cost (in SEK) of Servicing Different End-uses

End-use	Median household	80th percentile household	20th percentile household
	Using average spot price		
Heating	14.787	18.591	5.098
Lighting	1.331	1.537	1.028
Kitchen	1.365	1.660	0.955
Electronic media	1.813	2.441	1.252
Laundry	0.325	0.497	0.144
Total	19.261	24.726	8.477
	Using maximum spot price		
Heating	27.204	34.093	9.474
Lighting	2.559	2.945	1.995
Kitchen	2.637	3.241	1.834
Electronic media	3.384	4.535	2.344
Laundry	0.632	0.964	0.300
Total	36.416	45.778	15.947

Notes: Cost computations are based on load curves estimated for average February working days, matched with average and maximum February daily spot prices.

Table 4: Cost Reductions (% of Daily Total Cost) Due to Load Shift

Hours shifted	Median household	80th percentile household	20th percentile household
	Using average spot price		
1h	0.003	−0.153	0.422
2h	0.313	0.148	1.294
3h	0.772	0.768	2.287
4h	1.220	1.350	3.182
5h	1.584	1.824	3.958
	Using maximum spot price		
1h	0.186	−0.323	1.586
2h	0.974	0.456	3.805
3h	1.977	2.009	6.208
4h	2.918	3.323	8.241
5h	3.738	4.546	10.112

Notes: Cost savings computations are based upon the estimated cost of servicing provided in Table 3. Negative entries represent cost increases.

as the implications of using more extreme prices, such as the maximum February price. Savings in total cost are presented in Table 4, and those pertaining to individual end-uses are presented in Table 5.

It is evident from Table 4 that the total cost decreases overall are surprisingly small, and this holds for all three type of households although the cost savings in percentage are largest for households with low consumption.[27] Even if we shift the whole load curve five hours ahead, the

27. At first glance, this might suggest that households with lower consumption levels are more likely to respond to price variation. However, it is not clear whether households care about cost savings in relative (percentage) or absolute

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Table 5: End-use Cost Reductions (% of Daily Total Cost) Due to Load Shift

Hours shifted	Heating	Kitchen	Light	Electronic media	Laundry
			Using average spot price		
1h	−0.015	0.674	0.800	0.885	1.135
2h	0.075	2.490	3.134	1.973	2.588
3h	0.286	4.172	6.062	3.270	4.142
4h	0.435	5.415	8.434	4.400	4.965
5h	0.492	6.105	10.124	5.282	5.907

Notes: Cost savings are computed as in Table 4.

daily cost decreases by only 1.58 percent, or roughly 0.3 SEK for the median household at average prices. The cost savings are, as expected, larger for maximum prices, but are still relatively small; only 3.7 percentage or 1.25 SEK.

Of course, the cost savings would have been even smaller had the household only shifted a part of the load, e.g. heating. At first glance, the cost savings for some of the end-uses, from Table 5, might seem substantial, with up to ten percent decrease in daily cost of servicing when lighting use is shifted five hours. However, we recall from Table 3 that the cost of servicing lighting is a rather small part of the total daily cost; as a result, the average household would only save roughly 0.1 SEK (less than *one percent* of daily total cost) from shifting lighting. Shifting heating load, which is by far the biggest end-use, by five hours only leads to a half-percent reduction in its cost of servicing. To summarize, sizable reductions in cost of servicing are seen only for a few end-uses—particularly lighting and laundry—and that for shifts of three hours or more, indicating that there is little possibility for sizeable reduction in total cost from the very moderate shifts (two hours or less) that may be considered practicable.

Finally, it is important to bear in mind that these are the cost changes for an average February working day (using the load curve and prices for an average February working day and average February prices). Hence, for some days the cost reductions are possibly larger while for other days, cost reductions are likely lower. In particular, while the potential cost savings increase with price variation, if households are unable to respond to price peaks (e.g. due to the restrictions discussed previously) their costs will increase substantially for those days.

The cost savings illustrated in Table 4 are likely a best case scenario, for several reasons. First, as already mentioned, roughly half the variation in wholesale prices is transmitted to retail prices, implying reduced price variation and hence, lower cost savings. Secondly, the load shifting pattern illustrated above is likely not feasible, in reality. Indeed, we consider shifting of (total) load across as many as three hours or more as highly unlikely, since it requires households to completely alter their habits. It seems reasonable to believe that such a change in habits would lead to significant disutility for the household, at least in the short run when technology is fixed.

In our load shift experiments, we treat the spot price as exogenous, a reasonable assumption when few households are on real time pricing schemes. However, if a majority of households switch to real time pricing and adjust their consumption to hourly prices, two distinct channels of effect upon welfare emerge. The first channel is direct, via reduced price variation that, one would antic-

terms. Further, note that the costs associated with for example neccesary metering equipment are same for all households, and such costs are not evidently not included in the above calculations. Therefore, it is not certain that policy makers should interpret this result as an argument for promoting RTP to households with low(er) consumption levels.

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ipate, leads to reduced cost savings, as also noted elsewhere in the literature. The second channel, however, is via reduced congestion across regions, leading to potentially sizeable cost reduction, for at least certain consumers. Overall, the direction of effect in such a case can be ambiguous. An exploration of these issues, as already mentioned, is only feasible in a systemic model and is beyond the scope of our analysis.

6. DISCUSSION AND CONCLUSIONS

This paper set out to explore, using a unique data set on household hourly and appliance-level electricity consumption, the potential for, and cost implications (to retailers and consumers) of Sweden's thrust on real time pricing for residential electricity use. The appliance-specific nature of the metered data we use provides a unique opportunity to obtain more detailed understanding of end-use-specific electricity consumption patterns. We estimate end-use specific load curves (conditional on household characteristics) for detached houses on weekdays, and analyze how these correlate to possible restrictions on substitutability of load within the day, such as working hours, outdoor temperature, and (lack of) daylight. We do not explicitly explore substitutability of load across hours, but rather analyze possible *restrictions* on substitutability that may impose significant limitations on any short-run attempt to shift load from "expensive" to "cheap" hours. Our findings from the estimated load curves are that household total load has two peaks corresponding, roughly, to the morning pre-office hours (6–8 AM) and evening post-return-to home hours (6–9 PM). This is the period when the Nord pool spot prices are at their highest i.e. households consume the most when prices are their highest.

At end-use level, our analysis sheds light on relatively intuitive facts; households use heating when it is cold, lighting when it is dark and cooking before they leave for work and when they return home. Unsurprisingly, we find that the end uses with large shares of total load are heating, lighting and cooking, in that order. Based on these results, it is not evident that in the short-run, households have the possibility of re-allocating electricity consumption across hours, as this would essentially imply that households cook dinner during the night, turn on lights when electricity is cheap and adjust heating to prices, rather than to outdoor temperature. However, even in the presence of such restrictions, households may still adjust consumption to prices if the cost savings are substantial. By matching the estimated load curves with corresponding spot prices, we are able to explore potential cost-savings from re-allocating electricity consumption from peak to off-peak hours. We find very small gains; only 2–4% of reduction in daily cost obtain from shifting load up to five hours ahead. These results, we believe, may actually be interpreted as a best case scenario. On the other hand, it is also important to point out that as the share of intermittent generation increases, the price variation, and hence potential cost savings, may well increase. However, although potential cost savings increase in price variation, restrictions to load shifting may impose significant cost increases if households are unable to re-allocate load.

Our results, while novel and plausible, suffer from a few drawbacks which call for caution in interpretation as well as in direct application to policy. Foremost of the drawbacks is the absence of household price information, as a result of which our estimates of cost savings may well be pessimistic. Evidence for the importance of price for determination of demand in a RTP context is sparse, particularly for Sweden. Nonetheless, there is some recent evidence for the U.S. (see Jessoe et al. (2014)) indicating that the effect of dynamic price upon demand is rather more nuanced than conventionally assumed. Furthermore, the limited geographic variation in the households in our sample calls for some caution when extrapolating the results to the entire Swedish population. Finally, as already noted, the effect of the RTP scheme upon the system peak is not accounted for

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here. In light of these considerations, we offer our estimates of cost changes as a baseline for, and a spur to, further investigation of different aspects of efficient pricing of electricity for Sweden.

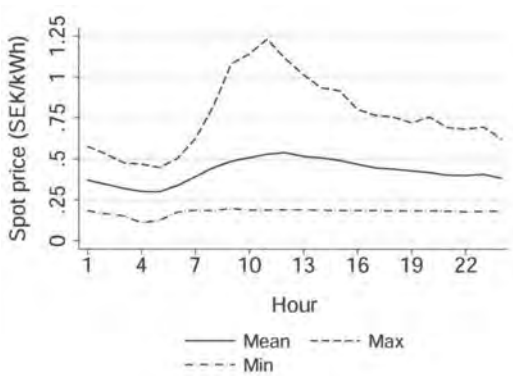
We conclude with some thoughts on the broader implications of our study for RTP, and on the emission implications of dynamic pricing for Sweden, an aspect so far not mentioned. Both in Sweden and elsewhere, policy makers and economists have put much faith in dynamic pricing and associated (theoretical) efficiency gains. The results of our study appears to lend support to the view, expressed in a few other recent studies, that many of the previous findings in the literature regarding the benefits of RTP may be based on optimistic assumptions about households' ability, and incentives, to adjust consumption to prices. Nonetheless, much more work is needed before we can fully understand the potential, practicability, and efficiency of real time pricing for Sweden.

In the Swedish case, given that only peak capacity is polluting, load shifting as a result of dynamic pricing has significant implications for emissions from Swedish electricity generation. Indeed, either peak conservation or reduction in peak load via re-allocation of consumption at a large scale is likely to imply a substantial reduction in (the already small) peak generation, and hence, emissions from electricity generation. Similar to the case of the U.S., investigated in Holland and Mansur (2008), where dynamic pricing is seen to reduce emissions, there is scope for emission reduction in the Swedish case too. In the presence of the EU ETS, where Swedish producers have to purchase emission credits, avoided peak generation has added private (to the producers) and social (avoided emissions) benefits, beyond retailer and consumer cost reduction, implying that these benefits must also be considered in any computation of the economy-wide welfare implication of dynamic pricing. Investigating these issues, while beyond the scope of the current analysis, is clearly an interesting and policy-relevant extension.

7. APPENDIX

7.1 Load Curves for June

Figure 7: Nord Pool Spot Prices for Weekdays in June



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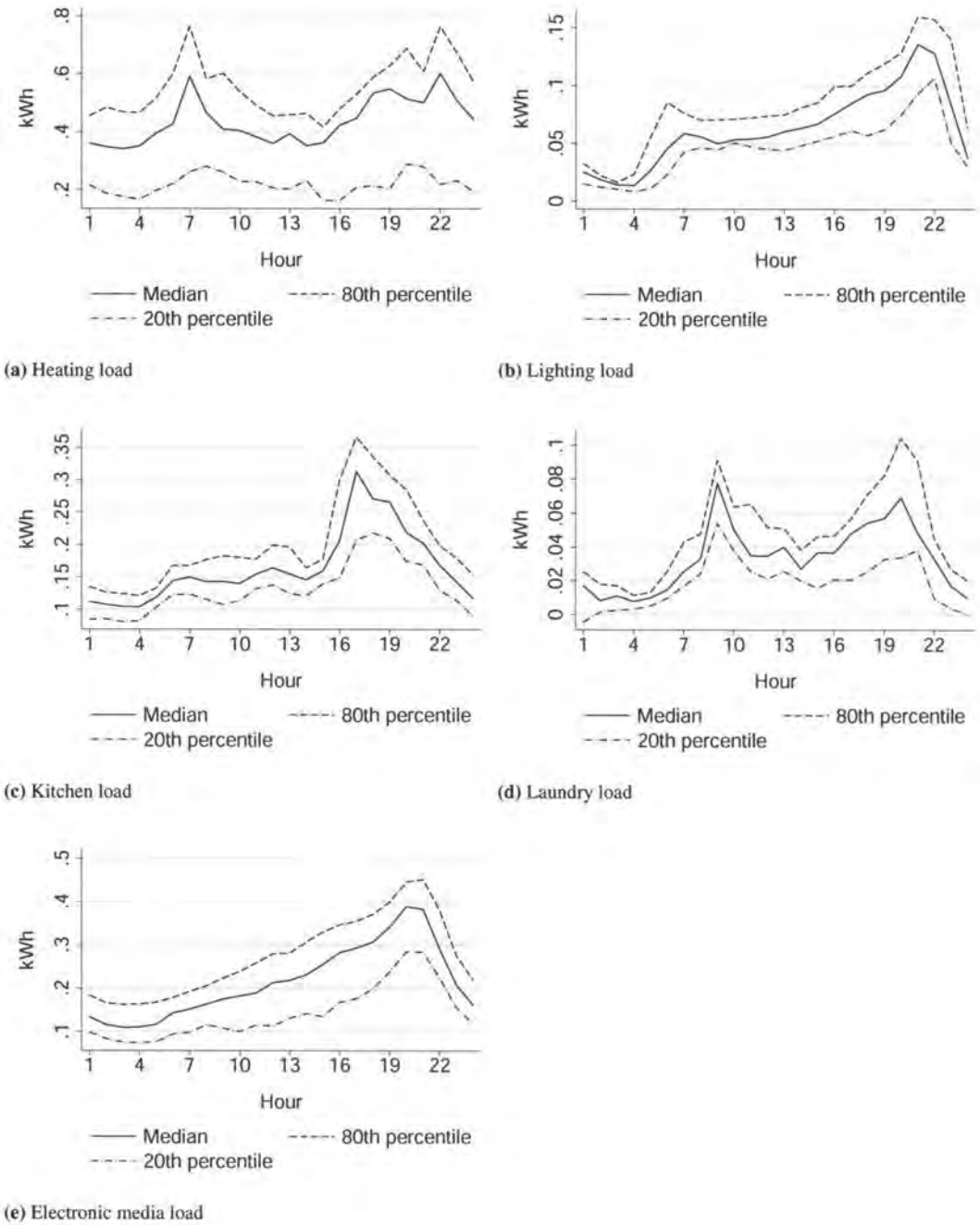
7.2 Load Curve: Goodness-of-Fit

Figure 8: End-use Load Curves for Average June Weekdays



All SUR regressions used to generate the load curves in Section 5.2 pass a battery of specification tests commonly used to assess the SUR system (estimated here using the FGLS approach). These tests encompass the following hypotheses: (i) all coefficients excluding the constant and year-fixed effects are zero (i.e. $\beta = [\beta_1, \ldots, \beta_{24}] = 0$, in the notation of equation (1)); and (ii) the Breusch-Pagan test of correlation of residuals across all equations (i.e. a null of "no correlation").

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We note that test outlined in (i) may be viewed as a test for "model goodness of fit", particularly when fixed effects are used. As already noted, GLS is not equivalent to OLS in our estimation framework, and therefore, the (Breusch-Pagan) test for cross-equation correlation is not a determining factor for the choice of GLS. We are able to reject the null for all of the tests, whose results are reported in Table 6.

Table 6: Goodness-of-Fit Measures for February Load Curve Estimation

	N	Wald test	Breusch-Pagan test
Heating	40	0.000	0.000
Lighting	42	0.000	0.000
Kitchen	42	0.000	0.000
Electronic media	42	0.000	0.000
Laundry	42	0.000	0.000

Notes: p-values for the specific test indicated reported. Note that the column labelled "N" reports the number of observations in each of the 24 hourly equations.

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FortisBC Inc.

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2022 and 2021

Independent Auditor's Report

To the Shareholder and the Board of Directors of
FortisBC Inc.

Opinion

We have audited the consolidated financial statements of FortisBC Inc. (the "Corporation"), which comprise the consolidated balance sheets as at December 31, 2022 and 2021, and the consolidated statements of earnings, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2022 and 2021, and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America ("US GAAP").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

A key audit matter is a matter that, in our professional judgment, was of most significance in our audit of the consolidated financial statements for the year ended December 31, 2022. This matter was addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on this matter.

Impact of Rate Regulation on the Financial Statements — Refer to Note 2 to the Financial Statements

Key Audit Matter Description

The Corporation is subject to rate regulation and annual earnings oversight by the British Columbia Utilities Commission ("BCUC"). Rates and resultant earnings of the Corporation are determined under performance-based rate-setting mechanism. The regulation of rates is premised on reasonable opportunity to recover prudently incurred costs and an allowed rate of return on common shareholders' equity ("ROE"). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as

property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a key audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation has indicated they expect to recover costs from customers through regulated rates, there is a risk that the BCUC will not approve full recovery of the costs incurred. Auditing these matters required especially subjective judgement and specialized knowledge of accounting for rate regulation due to its inherent complexities.

How the Key Audit Matter was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Evaluating the likelihood of recovery in future rates or of a future reduction in rates by assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information.
- For regulatory matters in process, inspecting the Corporation's filings and intervenor filings for any evidence that might contradict management's assertions. We obtained an analysis from management regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

Other Information

Management is responsible for the other information. The other information comprises Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with US GAAP, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our

opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Brenton Francis.

/s/ Deloitte LLP

Chartered Professional Accountants
Vancouver, British Columbia
February 9, 2023

FortisBC Inc.
Consolidated Balance Sheets
As at December 31
(in millions of Canadian dollars)

ASSETS		**2022**		2021
Current assets				
Accounts receivable and other current assets, net (notes 4 and 22)	**$**	**68**	$	66
Inventories		**1**		1
Prepaid expenses		**3**		2
Regulatory assets (note 8)		**8**		7
Total current assets		**80**		76
Property, plant and equipment, net (note 6)		**1,784**		1,720
Intangible assets, net (note 7)		**68**		65
Regulatory assets (note 8)		**412**		424
Other assets (note 5)		**16**		17
Goodwill (note 9)		**235**		235
TOTAL ASSETS	**$**	**2,595**	$	2,537
LIABILITIES AND EQUITY				
Current liabilities				
Credit facilities (note 21)	**$**	**65**	$	116
Accounts payable and other current liabilities (notes 10 and 22)		**97**		98
Current portion of long-term debt (notes 11 and 20)		**25**		-
Current portion of finance lease obligations (note 12)		**1**		1
Regulatory liabilities (note 8)		**11**		5
Total current liabilities		**199**		220
Long-term debt (note 11 and 20)		**853**		779
Finance lease obligations (note 12)		**335**		332
Regulatory liabilities (note 8)		**55**		34
Deferred income tax (note 19)		**240**		226
Other liabilities (notes 13 and 15)		**22**		67
Total liabilities		**1,704**		1,658
Commitments (note 23)				
Equity				
Common shares [1] (note 14)		**299**		299
Additional paid-in capital		**322**		322
Retained earnings		**270**		258
Total equity		**891**		879
TOTAL LIABILITIES AND EQUITY	**$**	**2,595**	$	2,537

[1] 500 million authorized common shares with a par value of $100 each; 3.0 million issued and outstanding at December 31, 2022 and 2021.

Approved on behalf of the Board:

(Signed by) Peter Blake
Director

(Signed by) Roger Dall'Antonia
Director

See accompanying notes to these Consolidated Financial Statements.

FortisBC Inc.
Consolidated Statements of Earnings
For the years ended December 31
(in millions of Canadian dollars)

	2022	2021
Revenue (note 16)	**$ 474**	$ 454
Expenses		
Power purchase costs (note 12)	**141**	136
Operating costs (notes 4, 12 and 22)	**106**	101
Property and other taxes	**17**	17
Depreciation and amortization (notes 6, 7 and 8)	**67**	65
Total expenses	**331**	319
Operating income	**143**	135
Other income	**6**	5
Finance charges (note 17)	**76**	73
Earnings before income taxes	**73**	67
Income tax expense (note 19)	**12**	11
Net earnings	**$ 61**	$ 56

FortisBC Inc.
Consolidated Statements of Changes in Equity
For the years ended December 31
(in millions of Canadian dollars)

	Common Shares *(# millions)*	**Common Shares**	**Additional Paid-in Capital**	**Retained Earnings**	**Total**
As at December 31, 2020	2.7	$ 269	$ 322	$ 249	$ 840
Net earnings	-	-	-	56	56
Issuance of common shares	0.3	30	-	-	30
Dividends on common shares	-	-	-	(47)	(47)
As at December 31, 2021	3.0	$ 299	$ 322	$ 258	$ 879
Net earnings	**-**	**-**	**-**	**61**	**61**
Dividends on common shares	**-**	**-**	**-**	**(49)**	**(49)**
As at December 31, 2022	**3.0**	**$ 299**	**$ 322**	**$ 270**	**$ 891**

See accompanying notes to these Consolidated Financial Statements.

FortisBC Inc.
Consolidated Statements of Cash Flows
For the years ended December 31
(in millions of Canadian dollars)

	2022	2021
Operating activities		
Net earnings	**$ 61**	$ 56
Adjustments to reconcile net earnings to cash from operating activities:		
Depreciation and amortization (notes 6, 7 and 8)	**67**	65
Accrued employee future benefits	**(3)**	(1)
Equity component of allowance for funds used during construction (note 6)	**(1)**	(1)
Change in regulatory assets and liabilities	**12**	8
Change in working capital (note 18)	**(4)**	6
Cash from operating activities	**132**	133
Investing activities		
Property, plant and equipment additions (note 18)	**(122)**	(127)
Intangible asset additions	**(8)**	(8)
Contributions in aid of construction	**9**	9
Change in other assets and other liabilities	**(9)**	(10)
Cash used in investing activities	**(130)**	(136)
Financing activities		
Net (repayment of) proceeds from credit facility (note 21)	**(51)**	46
Proceeds from issuance (repayment) of long-term debt (note 11)	**100**	(25)
Debt issuance costs	**(1)**	-
Repayment of finance lease obligations	**(1)**	(1)
Issuance of common shares	**-**	30
Dividends on common shares	**(49)**	(47)
Cash (used in) from financing activities	**(2)**	3
Net change in cash	**-**	-
Cash at beginning of year	**-**	-
Cash at end of year	**$ -**	$ -

Supplementary Information to Consolidated Statements of Cash Flows (note 18).

See accompanying notes to these Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

FortisBC Inc. ("FBC" or the "Corporation") is a wholly-owned subsidiary of FortisBC Pacific Holdings Inc. ("FortisBC Pacific") which is an indirect wholly-owned subsidiary of Fortis Inc. ("Fortis"). Fortis shares are listed on both the Toronto Stock Exchange and the New York Stock Exchange.

FBC is an integrated, regulated electric utility operating in the southern interior of British Columbia ("BC"), serving approximately 187,900 customers directly and indirectly. The Corporation's business includes four hydroelectric generating plants, and approximately 7,300 kilometers of transmission and distribution power lines, and a historical peak demand of 835 megawatts, which occurred during the fourth quarter of 2022.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and are presented in Canadian dollars unless otherwise specified. In management's opinion, the Consolidated Financial Statements include all adjustments that are necessary to present fairly the consolidated financial position of the Corporation.

The Consolidated Financial Statements include the accounts of the Corporation and its subsidiaries. All intercompany transactions and balances have been eliminated upon consolidation.

An evaluation of subsequent events through February 9, 2023, the date these Consolidated Financial Statements were issued, was completed to determine whether any circumstances warranted recognition or disclosure of events or transactions in the Consolidated Financial Statements as at December 31, 2022. No subsequent events have been identified for disclosure in these Consolidated Financial Statements.

Regulation

The Corporation is regulated by the British Columbia Utilities Commission ("BCUC"). Pursuant to the *Utilities Commission Act* (British Columbia), the BCUC regulates such matters as rates, construction plans, and financing.

The Corporation's Consolidated Financial Statements have been prepared in accordance with US GAAP, including certain accounting treatments that differ from those for enterprises not subject to rate regulation. The impacts of rate regulation on the Corporation's operations for the years ended December 31, 2022 and 2021 are described in these "Summary of Significant Accounting Policies", note 3 "Regulatory Matters", note 6 "Property, Plant and Equipment", note 7 "Intangible Assets", note 8 "Regulatory Assets and Liabilities", note 12 "Leases", note 13 "Other Liabilities", note 15 "Employee Future Benefits", note 17 "Finance Charges", and note 19 "Income Taxes".

When the BCUC issues decisions affecting the financial statements, the effects of the decision are usually recorded in the period in which the decision is received. In the event that a regulatory decision is received after the balance sheet date but before the Consolidated Financial Statements are issued, the facts and circumstances are reviewed to determine whether it is a recognized subsequent event.

Cash

Cash includes cash and short-term deposits with maturities of three months or less from the date of deposit.

Allowance for Credit Losses

The Corporation records an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. The credit loss allowance is estimated based on historical experience, current conditions, reasonable and supportable economic forecasts, and accounts receivable aging. In addition to historical collection patterns, the Corporation considers customer class, customer size, economic indicators and certain other risk characteristics when evaluating the credit loss allowance. Accounts receivable are written-off in the period in which the receivable is deemed uncollectible.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Regulatory Assets and Liabilities

The BCUC has the general power to include or exclude costs, revenues, losses or gains in the rates of a specified period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs incurred that will be, or are probable to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the BCUC could alter the amounts subject to deferral, at which time the change would be reflected in the Consolidated Financial Statements. For regulatory assets and liabilities which are amortized, the amortization is approved by the BCUC. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Inventories

Inventories represent materials and supplies held for day-to-day operations and for the maintenance of property, plant and equipment. Inventory held for construction or used only in connection with an item of property, plant and equipment is classified as property, plant and equipment. Inventory is measured at the lower of average cost and net realizable value.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated depreciation and unamortized contributions in aid of construction (“CIAC”). Cost includes all direct expenditures, betterments and replacements and as prescribed by the BCUC, an allocation of overhead costs and both a debt and an equity component of allowance for funds used during construction (“AFUDC”) at approved rates.

Certain additions to property, plant and equipment are made with the assistance of CIACs from customers when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers’ specific requirements.

Depreciation is based on rates approved by the BCUC and is calculated on a straight-line basis on the investment in property, plant and equipment commencing at the beginning of the year following when the asset is available for use.

As approved by the BCUC, the remaining book value after the removal of property, plant and equipment is charged to accumulated depreciation. It is expected that these amounts charged to accumulated depreciation will be reflected in future depreciation expense when refunded or collected in customer rates.

As approved by the BCUC, removal costs are collected as a component of depreciation on an accrual basis, with actual removal costs incurred drawing down the accrual balance. Removal costs are the direct costs incurred by the Corporation in taking assets out of service, whether through actual removal of the asset or through disconnection from the transmission or distribution system.

Intangible Assets

Intangible assets are comprised of right of ways and software not directly attributable to the operation of property, plant and equipment and are recorded at cost less accumulated amortization. Included in the cost of intangible assets are all direct expenditures, betterments and replacements and, as prescribed by the BCUC, an allocation of overhead costs and both a debt and equity component of AFUDC at approved rates.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful lives and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization is based on rates approved by the BCUC and is calculated on a straight-line basis commencing at the beginning of the year following when the asset is available for use.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Intangible assets with indefinite useful lives are not subject to amortization and are tested for impairment annually or more frequently if events or changes in circumstances indicate the asset may be impaired. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

No impairment provision has been determined for the years ended December 31, 2022 and 2021.

Leases

Leases that transfer to the Corporation substantially all the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Included as leases are any arrangements that qualify as leases by conveying the right to use a specific asset.

When a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration, a right-of-use asset and lease liability is recognized on the balance sheet. At inception, the right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components and fixed non-lease components, which the Corporation accounts for as a single lease component.

The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised. Leases with a term of twelve months or less are not recorded on the balance sheet but are recognized as lease expense straight-line over the lease term.

Finance leases are amortized over the lease term, except where ownership of the asset is transferred at the end of the lease term, in which case finance leases are amortized over the estimated service life of the underlying asset. Where the BCUC has approved recovery of the lease payments for rate-setting purposes instead of the depreciation expense and finance charges otherwise recognized for accounting purposes, specifically for the Brilliant Power Purchase Agreement (“BPPA”) and the Brilliant Terminal Station (“BTS”) included in note 12 “Leases”, the depreciation expense related to the lease is modified to conform with the rate-setting process. Therefore, the total depreciation expense and finance charges recognized during a period equals the power purchase costs or operating expense included in allowable costs for rate-making purposes during that period, with the difference recognized as a regulatory asset to be recovered from customers over the term of the related arrangements.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Asset-impairment testing is carried out at the enterprise level to determine if assets are impaired. The recovery of regulated assets’ carrying value, including a fair return on capital or assets, is provided through customer electricity rates approved by the BCUC. The net cash inflows for the Corporation are not asset-specific but are pooled for the entire regulated utility. There was no impairment of regulated long-lived assets for the years ended December 31, 2022 and 2021.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any write-down for impairment.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Impairment testing is performed if any event occurs or if circumstances change that would indicate that the fair value of the Corporation was below its carrying value. If that is the case, goodwill is written down to estimated fair value and an impairment loss is recognized. No such event or changes in circumstances occurred during 2022 or 2021.

Otherwise, the Corporation performs an annual assessment of goodwill which was performed by the Corporation during 2022 and it was concluded that it is more likely than not that the fair value of the reporting unit was greater than the carrying value and that goodwill was not impaired.

Asset Retirement Obligations

The Corporation recognizes the fair value of a future Asset Retirement Obligation ("ARO") as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Corporation concurrently recognizes a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The fair value of the ARO is estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the ARO is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are recognized as a regulatory asset using the effective interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

The Corporation has AROs for which the obligations cannot be reasonably estimated at this time. These AROs are primarily associated with the Corporation's hydroelectric generating facilities and assets associated with interconnection facilities. While each of the foregoing will have legal asset retirement obligations (i.e. land and environmental remediation and/or removal of assets), the final date of removal of the related assets and the costs to do so cannot be reasonably determined at this time. There is a reasonable expectation that asset retirement costs would be recoverable through future rates.

Revenue Recognition

Revenue from Contracts with Customers

Electricity revenue is billed at rates approved by the BCUC and is bundled to include the cost of generating, transmitting and distributing electricity. The rate includes customer service as well as other corporate and service functions.

The majority of the Corporation's revenue is derived from electricity sales to residential, commercial, wholesale, and industrial customers. Most of the Corporation's contracts have a single performance obligation, the delivery of electricity. Substantially all of the Corporation's performance obligations are satisfied over time as electricity is delivered because of the continuous transfer of control to the customer, generally using an output measure of progress, kilowatt hours ("kWh") delivered. The billing of electricity sales is based on the reading of customer meters, which occurs on a systematic basis throughout the month. Electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each reporting date. No component of the transaction price is allocated to unsatisfied performance obligations.

Other contract revenue from customers includes surplus capacity sales, third party contract work and pole attachments. Surplus capacity sales are recognized when the capacity or energy is delivered at the amount of consideration set out in the contracts. Third party contract revenue relates to operations, maintenance and management services rendered to third party owned hydroelectric generation facilities and is recognized as services are provided. Pole attachment revenue is earned from third party attachments to utility infrastructure and is recognized over time.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria established by the BCUC are met. The Corporation has identified its Earnings Sharing Mechanism and Flow-through variances related to tariff-based revenue as alternative revenue.

The Earnings Sharing Mechanism allows for a 50/50 sharing of variances from allowed Return on Equity ("ROE") approved as part of the annual revenue requirements. This mechanism is in place until the expiry of the current Multi-Year Rate Plan ("MRP") for 2020 to 2024. In addition, alternative revenue includes variances in the forecast versus actual customer revenue in a flow-through deferral account to be either refunded to or recovered from customers in rates within two years.

Other Revenue (Expense)

Other revenue (expense) is primarily comprised of regulatory deferral adjustments resulting primarily from cost recovery variances in regulated forecasts used to set rates for electricity revenue. As part of the decision received on FBC's MRP application for the years 2020 to 2024 ("MRP Decision"), effective January 1, 2020 and effective through to the end of the MRP term, the Corporation has a flow-through deferral account that captures variances from certain regulated forecast revenues and other expenses, including those that are not controllable or associated with clean growth capital expenditures, and that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.

The Corporation disaggregates revenue by type of customer, as disclosed in note 16. This represents the level of disaggregation used by the Corporation to evaluate performance.

Employee Future Benefits

The Corporation sponsors a number of post-employment benefit plans. These plans include defined benefit, unfunded supplemental, and various other post-employment benefit ("OPEB") plans.

The cost of pensions and OPEBs earned by employees are actuarially determined as an employee accrues service. The Corporation uses the projected benefit pro-rata method based on years of service, management's best estimates of expected returns on plan assets, salary escalation, retirement age, mortality and expected future health-care costs. The discount rate used to value liabilities is based on Corporate AA bond yields with cash flows that match the timing and amount of the expected benefit payments under the plans. The Corporation uses a measurement date of December 31 for all plans.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and the fair market value of plan assets.

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and the fair value of plan assets that result from changes in assumptions and experience gains and losses, are amortized straight-line over the expected average remaining service life, or the expected average remaining life expectancy, of the employee group covered by the plans. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

The Corporation records the funded or unfunded status of its defined benefit pension plans and OPEB plans on the balance sheet. Unamortized balances relating to past service costs and net actuarial gains and losses have been recognized in regulatory assets and are expected to be recovered from customers in future rates. Subsequent changes to past service costs and net actuarial gains and losses are recognized as an expense, where required by the BCUC, or otherwise as a change in the regulatory asset or liability. The Corporation also provides a defined contribution pension arrangement to certain employees not covered by the defined benefit plans. Defined contribution plan costs are expensed by the Corporation as contributions are payable.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The Corporation capitalizes the eligible portion of the current service cost component of net benefit cost. The remaining portion of current service cost not capitalized is grouped in the Consolidated Statements of Earnings with other employee compensation costs arising from services rendered. The non-service cost components of net benefit cost are presented in other income.

Fair Value

Fair value is the price at which a market participant could sell an asset or transfer a liability to an unrelated party. A fair value measurement is required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. The fair values of the Corporation's financial instruments reflect point-in-time estimates based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flows. A fair value hierarchy exists that prioritizes the inputs used to measure fair value. The Corporation is required to record all derivative instruments at fair value except those which qualify for the normal purchases and normal sales exception.

Derivative Financial Instruments

Derivative instruments are recognized as either assets or liabilities on the balance sheet and are measured at fair value unless they meet the normal purchases and normal sales scope exception. The Corporation continually assesses its contracts, including its power purchase agreements, to determine whether they meet the criteria of a derivative, and if so, whether they qualify for the normal purchases and normal sales scope exception.

Debt Issuance Costs

Costs incurred to arrange debt financing are recognized as a direct deduction from the carrying amount of the debt liability and are accounted for using the effective interest method over the life of the related financial liability.

Sales Taxes

In the course of its operations, the Corporation collects sales taxes from its customers. When customers are billed, a current liability is recognized for the sales taxes included on the customer's bill. This liability is settled when the taxes are remitted to the appropriate government authority. The Corporation's revenue excludes the sales taxes.

Income Taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are more likely than not (greater than a 50 per cent chance) to be realized.

The deferred income tax assets and liabilities are measured using enacted income tax rates and laws that will be in effect when the temporary differences are expected to be recovered or settled. As a result of rate regulation, deferred income taxes incurred related to regulated operations have been offset by a corresponding regulatory asset or liability resulting in no impact on net earnings. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain regulatory asset and liability accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of deferred income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that is expected to be collected in rates once the amount becomes payable.

Any difference between the expense recognized and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment as described in note 8 "Regulatory Assets and Liabilities".

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

The Corporation recognizes a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. The tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50 per cent likely to be realized upon settlement. The difference between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to this guidance represents an unrecognized tax benefit.

Interest and penalties related to unrecognized tax benefits are recognized in income tax expense.

Segment Reporting

The Corporation has a single reportable segment.

Use of Accounting Estimates

The preparation of the Corporation's financial statements in accordance with US GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, regulatory decisions, current conditions and various other assumptions believed to be reasonable under the circumstances. The use of estimates is described in the "Summary of Significant Accounting Policies", in note 8 "Regulatory Assets and Liabilities", and note 23 "Commitments". Certain estimates are also necessary since the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

New Accounting Policies

FBC considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board ("FASB"). During the year ended December 31, 2022, there were no ASUs issued by FASB that have a material impact on these Consolidated Financial Statements.

Future Accounting Pronouncements

Any ASUs issued by FASB that are not included in these Consolidated Financial Statements were assessed and determined to be either not applicable to the Corporation or not expected to have a material impact on these Consolidated Financial Statements.

3. REGULATORY MATTERS

Decision on Multi-Year Rate Plan ("MRP") for 2020 to 2024

In June 2020, the BCUC issued its decision on FBC's MRP application for the years 2020 to 2024 ("MRP Decision"). The approved MRP includes, amongst other items, a level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a forecast approach to the growth and sustainment capital, a number of service quality indicators designed to ensure the Corporation maintains service levels, and a 50/50 sharing between customers and the Corporation of variances from the allowed ROE.

Variances from the allowed ROE subject to sharing include other revenue and certain components of operating and maintenance costs, as well as variances in the utility's regulated rate base amounts, while variances associated with revenues and other expenses, including those that are not controllable or associated with clean growth capital expenditures, are subject to flow-through treatment and refunded to or recovered from customers.

In December 2021, the BCUC approved a rate increase of 3.47 per cent over 2021 rates, effective January 1, 2022. As part of this filing, a 2022 average rate base of $1,583 million was approved.

4. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

The timing of revenue recognition, billings, and cash collections results in billed and unbilled accounts receivable. The opening and closing balances of the Corporation's accounts receivable as at December 31 were as follows:

($ millions)	**2022**	2021
Accrued unbilled revenue from contracts with customers	**43**	36
Billed accounts receivable from contracts with customers	**19**	19
Receivables for third party services	**6**	11
Income and other taxes receivable	**2**	-
Other receivables and assets [1]	**1**	1
Amounts due from related parties (note 22)	**-**	2
Allowance for credit losses	**(3)**	(3)
Total accounts receivable and other current assets	**68**	66

[1] Representative of receivables not related to contracts with customers.

Accounts receivable are recorded net of an allowance for credit losses. The credit loss allowance recorded for the year ended December 31, 2022 considered current and forecasted economic conditions.

The change in the allowance for credit losses balance is as follows:

($ millions)	**2022**	2021
Beginning of year	**(3)**	(4)
Credit losses expensed	**(1)**	(1)
Credit losses deferred (note 8)	**-**	1
Write-offs, net of recoveries	**1**	1
End of year	**(3)**	(3)

5. OTHER ASSETS

($ millions)	**2022**	2021
Pension asset (note 15)	**14**	15
Other assets	**2**	1
Operating leases (note 12)	**-**	1
Total other assets	**16**	17

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2022	**Cost**	**Accumulated Depreciation**	**Book Value**	**Weighted Average Depreciation Rate**
($ millions)				
Generation	**370**	**(81)**	**289**	**1.6%**
Transmission	**834**	**(260)**	**574**	**1.7%**
Distribution	**731**	**(146)**	**585**	**2.0%**
Plant, buildings and equipment	**175**	**(58)**	**117**	**5.4%**
Finance lease assets	**310**	**(106)**	**204**	**2.0%**
Assets under construction	**15**	**-**	**15**	**-**
Total property, plant and equipment	**2,435**	**(651)**	**1,784**	

December 31, 2021	Cost	Accumulated Depreciation	Book Value	Weighted Average Depreciation Rate
(*$ millions*)				
Generation	353	(76)	277	1.6%
Transmission	782	(249)	533	1.7%
Distribution	694	(136)	558	2.0%
Plant, buildings and equipment	166	(56)	110	5.6%
Finance lease assets	306	(100)	206	2.0%
Assets under construction	36	-	36	-
Total property, plant and equipment	2,337	(617)	1,720	

As allowed by the BCUC, during the year ended December 31, 2022, the Corporation capitalized a debt component of AFUDC of $1 million (December 31, 2021 - $1 million) and an equity component of AFUDC of $1 million (December 31, 2021 - $1 million), and approved capitalized overhead costs of $10 million (December 31, 2021 - $10 million).

Depreciation of property, plant and equipment, including a net salvage provision, for the year ended December 31, 2022 totaled $57 million (December 31, 2021 - $55 million).

Included in the book value of property, plant and equipment are asset retirement costs totaling $nil (December 31, 2021 - $1 million). Depreciation on the asset retirement costs was recorded in other recoverable costs in regulatory assets (note 8), and the corresponding liability has been recorded as an ARO in other liabilities (note 13).

Finance lease assets include the BPPA and BTS arrangements. Depreciation of $6 million (December 31, 2021 - $5 million) on the BPPA finance lease asset was recorded in the BPPA lease costs regulatory asset (note 8) and depreciation of $1 million (December 31, 2021 - $1 million) on the BTS finance lease asset was recorded in the BTS lease costs regulatory asset (note 8).

7. INTANGIBLE ASSETS

December 31, 2022	**Cost**	**Accumulated Amortization**	**Book Value**
($ millions)			
Software	**58**	**(24)**	**34**
Land rights	**40**	**(6)**	**34**
Total intangible assets	**98**	**(30)**	**68**

December 31, 2021	Cost	Accumulated Amortization	Book Value
($ millions)			
Software	56	(24)	32
Land rights	39	(6)	33
Total intangible assets	95	(30)	65

There was no impairment of intangible assets for the years ended December 31, 2022 and 2021.

Amortization of intangible assets for the year ended December 31, 2022 totaled $6 million (December 31, 2021 - $5 million).

Amortization of software is recorded on a straight-line basis using an average amortization rate of 9.1 per cent (December 31, 2021 – 9.1 per cent). Amortization of land rights is recorded on a straight-line basis using an amortization rate of 1.2 per cent (December 31, 2021 – 1.2 per cent).

Included in the cost of land rights at December 31, 2022 was $18 million (December 31, 2021 - $18 million) not subject to amortization.

The following is the estimated amortization expense for each of the next five years:

($ millions)	
2023	**5**
2024	**5**
2025	**4**
2026	**3**
2027	**2**

8. REGULATORY ASSETS AND LIABILITIES

Based on existing regulatory orders or the expectation of future regulatory orders, the Corporation has recorded the following amounts, net of income tax and amortization where applicable, which are expected to be recovered from or refunded to customers as at December 31:

($ millions)	**2022**	2021	**Remaining Refundable Period (Years)**
Regulatory assets			
Regulated asset for deferred income taxes (note 19) (i)	**241**	228	Ongoing
BPPA lease costs (note 12) (ii)	**128**	122	34
Demand side management program (iii)	**37**	35	10
Pension and OPEB unrecognized actuarial losses and past service costs (note 15) (iv)	**-**	33	Ongoing
Income taxes recoverable on OPEBs (v)	**5**	5	Ongoing
BTS lease costs (note 12) (vi)	**4**	5	30
Pension and OPEB cost variance (vii)	**2**	-	3
Other recoverable costs (viii)	**3**	3	Various
Total regulatory assets	**420**	431	
Less: current portion	**8**	7	
Long-term portion of regulatory assets	**412**	424	

(*$ millions*)	**2022**	2021	**Remaining Refundable Period (Years)**
Regulatory liabilities			
Net salvage provision (ix)	**35**	27	Ongoing
Flow-through variances (x)	**19**	9	1
Net pension and OPEB unrecognized actuarial gains and past services costs (note 15) (iv)	**8**	-	Ongoing
Earnings sharing mechanism (xi)	**2**	2	1
Debt issuance costs under effective interest method (xii)	**1**	1	Up to 30
Other refundable costs (viii)	**1**	-	Various
Total regulatory liabilities	**66**	39	
Less: current portion	**11**	5	
Long-term portion of regulatory liabilities	**55**	34	

Net amortization expense of regulatory assets and liabilities, excluding a net salvage provision, for the year ended December 31, 2022 totaled $4 million (December 31, 2021 - $5 million).

(i) Regulated Asset for Deferred Income Taxes

FBC recognizes deferred income tax assets and liabilities, and related regulatory liabilities and assets, for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future rates. Included in deferred income tax assets and liabilities are the future income tax effects of the subsequent settlement of the related regulatory liabilities and assets through customer rates.

The regulatory asset balance is expected to be recovered from customers in future rates when the deferred taxes become payable, and is not subject to a regulatory return.

8. REGULATORY ASSETS AND LIABILITIES (continued)

(ii) BPPA Lease Costs

The depreciation on the BPPA finance lease asset (note 6) and the interest expense associated with the BPPA lease obligation (note 17) are not being fully recovered by the Corporation in current customer rates since those rates include only the payments set out under the BPPA. The BPPA payments, including the related variable operating costs, are recovered as power purchase costs rather than as finance lease depreciation and interest expense. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates over the term of the arrangement, which ends in 2056, and is not subject to a regulatory return.

(iii) Demand Side Management Program

The Corporation's Demand Side Management ("DSM") program funds incentives and provides energy management services to promote efficiency programs for its customers. As approved by the BCUC, the Corporation recovers these costs in rates over a 10-year period.

(iv) Pension and OPEB Unrecognized Actuarial Losses or Gains and Past Service Costs

The net funded status, being the difference between the fair value of plan assets and the projected benefit obligation for pensions and OPEBs, is required to be recognized on the Corporation's balance sheet under ASC Topic 715, *Compensation – Retirement Benefits*. The amount required to make this net funded status adjustment, which would otherwise be recognized in Accumulated Other Comprehensive Income ("AOCI"), has instead been deferred as a regulatory asset or liability. The regulatory asset or liability balance represents the deferred portion of the actuarial gains or losses relating to pensions and OPEBs that is expected to be refunded to or recovered from customers in future rates as the deferred amounts are included as a component of future net benefit cost.

(v) Income Taxes Recoverable on OPEBs

The BCUC allows OPEB plan costs to be collected in customer rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. As approved by the BCUC, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer rates. This regulatory asset balance is expected to be recovered from customers in future rates.

(vi) BTS Lease Costs

The depreciation on the BTS finance lease asset (note 6) and the interest expense associated with the BTS lease obligation (note 17) have not been fully recovered by the Corporation in current customer rates since those rates include only the payments set out under an agreement to lease the BTS. The BTS payments, including the related variable operating costs, are recovered as operating costs rather than as finance lease depreciation and interest expense. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates over the term of the arrangement, and is not subject to a regulatory return.

(vii) Pension and OPEB Cost Variance

As approved by the BCUC, the pension and OPEB cost variance account accumulates differences between pension and OPEB expenses that are approved for recovery in rates and the actuarially determined pension and OPEB expense. The regulatory asset balance is expected to be recovered from customers in future rates over 3 years.

8. REGULATORY ASSETS AND LIABILITIES (continued)

(viii) Other Recoverable and Refundable Costs

Regulatory assets and liabilities that have been aggregated in the tables above as other items relate to smaller deferral accounts. These accounts either have been approved by the BCUC for recovery from or refund to customers or are expected to be approved. The approved amounts are being amortized over various periods depending on the nature of the costs. Included in other recoverable costs is the COVID-19 Customer Recovery Fund deferral account, which captures the otherwise uncollectible revenues associated with providing certain deferral and relief offerings to the Corporation's customers during the COVID-19 pandemic; as well as the cumulative transition amount that existed between the pension and OPEB amounts to be recognized under ASC Topic 715 which would otherwise would have been recognized in retained earnings, but instead were approved by the BCUC to be collected from customers over a term of twelve years beginning on January 1, 2012.

(ix) Net Salvage Provision

The net salvage provision account captures the provision for costs which will be incurred to remove assets from service in a future period. As actual removal costs are incurred, the net salvage provision account is drawn down. For the year ended December 31, 2022, $15 million (December 31, 2021 - $15 million) was collected from customers through depreciation expense to offset future removal costs which may be incurred. Actual removal costs incurred for the year ended December 31, 2022 were $7 million (December 31, 2021 - $12 million).

(x) Flow-through Variances

As part of the MRP Decision and effective January 1, 2020, the Corporation has a flow-through deferral account that captures certain variances from regulated forecast revenues and other expenses, including those that are not controllable or associated with clean growth expenditures, and that do not have separately approved deferral mechanisms, and flows those variances through customer rates in the following year.

(xi) Earnings Sharing Mechanism

The Earnings Sharing Mechanism deferral account captures the customer portion of the sharing of variances from the allowed ROE under the MRP Decision. The BCUC has approved the refund or recovery of these variances in customer rates in the following year.

(xii) Debt Issuance Costs Under Effective Interest Method

This balance represents the cumulative difference between applying the effective interest method for amortizing debt issuance costs and the straight-line amortization method used in setting customer rates. This regulatory liability represents the cumulative difference between the two amortization methods which will be refunded to customers over the term of the outstanding debt through future rates, and is not subject to a regulatory return.

9. GOODWILL

On May 31, 2004, Fortis, through a wholly owned subsidiary, acquired all of the issued and outstanding shares of FBC. The consideration paid for this acquisition has been recorded in the Corporation's financial statements using push-down accounting. In addition to goodwill of $220 million (December 31, 2021 - $220 million) for the excess of the purchase price paid by Fortis over the fair value of the net assets acquired, the Corporation has recognized additional paid-in capital related to the push-down of the acquisition accounting.

FBC has also recognized a total of $15 million (December 31, 2021 - $15 million) in goodwill related to the excess of the purchase price over the fair value of the net assets of electric utility businesses acquired by the Corporation in the Princeton area on December 31, 2006 and the Kelowna area on March 29, 2013.

There was no impairment of goodwill for the years ended December 31, 2022 and 2021.

10. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2022**	2021
Trade accounts payable	**38**	41
Power purchase and wheeling accruals	**16**	17
Employee compensation and benefits payable	**16**	15
Customer deposits	**15**	12
Interest payable	**9**	5
Pension and other post-employment benefits (note 15)	**1**	1
Amounts due to related parties (note 22)	**1**	2
Income and other taxes payable	**1**	4
Other current liabilities	**-**	1
Total accounts payable and other current liabilities	**97**	98

11. LONG-TERM DEBT

($ millions)	**2022**	2021
Secured Debentures		
8.80% Series G, due August 28, 2023	**25**	25
Unsecured Debentures		
5.60% Series 05-1, due November 9, 2035	**100**	100
5.90% Series 07-1, due July 4, 2047	**105**	105
6.10% Series 1, due June 2, 2039	**105**	105
5.00% Series 2, due November 24, 2050	**100**	100
4.00% Series 3, due October 28, 2044	**200**	200
3.62% Series 4, due December 6, 2049	**75**	75
3.12% Series 5, due May 11, 2050	**75**	75
4.16% Series 6, due March 14, 2052	**100**	-
Total long-term debt	**885**	785
Less: current portion of long-term debt	**25**	-
Total long-term debt, excluding current portion	**860**	785
Less: debt issuance costs	**7**	6
Total long-term debt, net of debt issuance costs	**853**	779

Secured and Unsecured Debentures

The Series G secured debentures are collateralized by a fixed and floating first charge on the assets of the Corporation. The secured Series G debentures are guaranteed by FortisWest Inc., a subsidiary of Fortis.

11. LONG-TERM DEBT (continued)

On March 10, 2022, FBC entered into an agreement with an affiliate of a Canadian Chartered Bank to sell $100 million of unsecured MTN Debentures. These MTN Debentures bear interest at a rate of 4.16 per cent to be paid semi-annually and mature on March 14, 2052. The closing of the issuance occurred on March 14, 2022, with net proceeds being used to repay existing credit facilities.

All of the Corporation's debentures are redeemable, in whole or in part, at the option of the Corporation, at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption.

The Corporation has externally imposed capital requirements to which it is subject to that include interest coverage ratios and limitations on the amount of debt that can be incurred relative to equity. As at December 31, 2022 and 2021, the Corporation was in compliance with these externally imposed capital requirements.

See note 23 "Commitments" for required principal and interest payments for long-term debt over the next five years and thereafter.

12. LEASES

Finance Leases

The Corporation has recognized finance leases for the BPPA, which is an arrangement that contains a lease for the purchase of the output of the Brilliant hydroelectric plant, and for the BTS, which relates to an agreement that contains a lease for the use of a substation. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which is composed of the original plant capital charge and periodic upgrade capital charges, as well as sustaining capital charges, and related variable power purchase costs. Under the BTS, FBC pays semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs. Given the impacts of accounting for regulated operations, the recognition of interest and amortization expense is equal to the amounts recovered in rates.

Operating Lease

In 2021, the Corporation leased an office facility from a related party, FortisBC Energy Inc. ("FEI"), with a remaining term of one year and, in 2022, the agreement was extended on a month to month basis. The rental payment is fixed throughout the term of the lease with no escalating factors and there are no additional variable payments above the fixed monthly rent.

The following table details supplemental balance sheet information related to the Corporation's leases for the year ended December 31:

($ millions)	**Classification**	**2022**	2021
Assets			
Long-term			
Operating lease	Other assets (note 5)	**-**	1
Finance leases	Property, plant and equipment, net (note 6)	**204**	206
Finance lease deferral	Regulatory assets (note 8)	**132**	127
Total lease assets		**336**	334
Liabilities			
Current			
Operating lease	Accounts payable and other current liabilities (note 10)	**-**	1
Finance leases	Current portion of finance lease obligations	**1**	1
Long-term			
Finance leases	Finance lease obligations	**335**	332
Total lease liabilities		**336**	334

12. LEASES (continued)

The following table presents the components of the Corporation's lease cost for the year ended December 31:

($ millions)	**2022**	2021
Finance lease cost – interest (note 17)	**33**	32
Variable lease cost – power purchase costs and operating costs	**12**	12
Total lease cost	**45**	44

As at December 31, 2022, the present value of the future cash flows required over the next five years and thereafter are as follows:

($ millions)	**Total**
2023	**34**
2024	**34**
2025	**35**
2026	**35**
2027	**36**
Thereafter	**1,001**
Subtotal	**1,175**
Less: amounts representing imputed interest	**839**
Total finance leases	**336**
Less: current portion	**1**
Long-term portion	**335**

The Corporation provides the following supplemental information related to its leases for the years ended December 31:

Lease Term and Discount Rate	**2022**	2021
Weighted-average remaining lease term (years)		
Operating lease	-	1
Finance leases	**33**	34
Weighted-average discount rate (%)		
Operating lease	**-**	3.0%
Finance leases	**5.1%**	5.1%

During the years ended December 31, 2022 and 2021, there were no right-of-use assets obtained in exchange for operating lease liabilities.

13. OTHER LIABILITIES

($ millions)	**2022**	2021
Pension and OPEB liabilities (note 15)	**21**	65
Other liabilities [1]	**1**	2
Total other liabilities	**22**	67

[1] Included in other liabilities is an ARO.

Asset Retirement Obligation

FBC has recognized an ARO based on an estimate of the fair value and timing of estimated future expenditures associated with the removal of insulating oil in certain electrical equipment that is contaminated with polychlorinated biphenyls ("PCBs"). The determination of the ARO is based on PCB regulations under the Canadian Environmental Protection Act, 1999 which govern the management and storage of PCBs as well as impose timelines for disposal based on certain criteria including type of equipment, in-use status and PCB-contamination thresholds. The Corporation must identify and remove certain levels of PCBs in certain of its electrical equipment assets by 2025 to be compliant with the PCB regulations.

13. OTHER LIABILITIES (continued)

The asset retirement cost has been capitalized to property, plant and equipment (note 6). Actual costs incurred upon settlement of an ARO are charged against the related liability to the extent of the accrued balance. Any difference between the actual costs incurred upon settlement of the ARO and the remaining balance is expected to be recognized as a regulatory asset or liability at that time.

The credit-adjusted risk-free discount rates used to calculate the present value of the obligation is 3.0 per cent. Total estimated undiscounted future cash flows required to comply with the PCB regulations between 2023 and 2024 is not material.

14. SHARE CAPITAL

Authorized Share Capital

The Corporation is authorized to issue 500,000,000 common shares, with a par value of $100 each and 500,000,000 preferred shares, with a par value of $25 each, issuable in series.

Common Shares

Issued and outstanding common shares as at December 31 are as follows:

	2022		2021	
	Number of Shares	**Amount ($millions)**	Number of Shares	Amount ($millions)
Outstanding, beginning of year	**2,991,510**	**299**	2,691,510	269
Issued	**-**	**-**	300,000	30
Outstanding, end of year	**2,991,510**	**299**	2,991,510	299

15. EMPLOYEE FUTURE BENEFITS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, and defined contribution plans. In addition to pensions, the Corporation provides OPEB for certain retired employees.

Defined Benefit Pension Plans

The Corporation sponsors three defined benefit pension plans, one of which is closed to new entrants. Retirement benefits are based on employees' years of credited service and remuneration. Corporation contributions to the plans are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were as at December 31, 2019 and 2021 and the dates of the next required valuations will be as at December 31, 2022 and 2024.

Supplemental Plans

Certain employees are eligible to receive supplemental benefits. The supplemental plans provide pension benefits in excess of statutory limits and are unfunded.

Defined Contribution Plans

The Corporation's cost related to the defined contribution arrangement is based upon a percentage of employee earnings. The Corporation's 2022 net benefit cost related to this arrangement was $2 million (December 31, 2021 - $1 million).

15. EMPLOYEE FUTURE BENEFITS (continued)

Other Post-Employment Benefits

The Corporation provides certain retired employees with OPEBs that include, depending on circumstances, supplemental health, dental and life insurance coverage. OPEBs are unfunded and the annual net benefit cost is recorded on an accrual basis based on independent actuarial determinations, considering, among other factors, health-care cost escalation. The date of the next required valuation will be as at December 31, 2024.

The financial positions of the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows as at December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Change in fair value of plan assets				
Balance, beginning of year	**263**	246	**-**	-
Actual (loss) return on plan assets	**(33)**	18	**-**	-
Employer contributions	**5**	5	**1**	1
Employee contributions	**3**	3	**-**	-
Benefits paid	**(10)**	(9)	**(1)**	(1)
Fair value, end of year	**228**	263	**-**	-
Change in projected benefit obligation				
Balance, beginning of year	**286**	280	**28**	28
Employee contributions	**3**	3	**-**	-
Current service cost	**6**	7	**1**	1
Interest costs	**9**	8	**1**	1
Benefits paid	**(10)**	(9)	**(1)**	(1)
Actuarial gain	**(78)**	(3)	**(9)**	(1)
Balance, end of year [1]	**216**	286	**20**	28
Funded / (Unfunded) Status	**12**	(23)	**(20)**	(28)

[1] The accumulated benefit obligation for defined benefit pension plans, excluding assumptions about future salary levels, was $189 million (December 31, 2021 - $253 million).

The following table summarizes the employee future benefit assets and liabilities and their classification in the Consolidated Balance Sheets as at December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Other assets (note 5)	**(14)**	(15)	**-**	-
Accounts payable and other current liabilities (note 10)	**-**	-	**1**	1
Other liabilities (note 13)	**2**	38	**19**	27
Net (asset) liability	**(12)**	23	**20**	28

15. EMPLOYEE FUTURE BENEFITS (continued)

The net benefit cost for the Corporation's defined benefit pension and supplemental plans and OPEB plans are as follows for the years ended December 31:

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Service costs	**6**	7	**1**	1
Interest costs	**9**	8	**1**	1
Expected return on plan assets	**(14)**	(13)	**-**	-
Amortization:				
Actuarial losses (gains)	**1**	2	**-**	(1)
Past service costs	**(1)**	(1)	**-**	-
Regulatory adjustment	**(1)**	-	**-**	1
Net benefit cost	-	3	**2**	2

The components of net benefit cost, other than the service cost component, are included in other income in the Consolidated Statements of Earnings for the years ended December 31, 2022 and 2021.

Defined Benefit Pension Plan Assets

The assets of the Corporation's funded defined benefit pension plans were invested on a weighted average as follows as at December 31:

	Target Allocation	2022	2021
Equities	**30% - 50%**	**41%**	37%
Fixed income	**30% - 70%**	**35%**	39%
Real estate and infrastructure	**0% - 30%**	**23%**	21%
Private equity	**0% - 5%**	**1%**	3%
		100%	100%

The investment policy for defined benefit plan assets is to optimize the risk-return ratio using a portfolio of various asset classes. FBC's primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans use quarterly rebalancing in order to achieve the target allocations while complying with the constraints of the Pension Benefits Standards Act of British Columbia and the Income Tax Act. The pension plans utilize external investment managers to execute the investment policy. Assets in the plans are held in trust by independent third parties. The pension plans do not directly hold any shares of FBC's parent or affiliated companies.

The fair value measurements of the Corporation's defined benefit pension plan assets by fair value hierarchy level, which are described in further detail in note 20 "Financial Instruments", are as follows as at December 31:

2022	**Level 1**	**Level 2**	**Level 3**	**Total**
($ millions)				
Cash	**1**	**-**	**-**	**1**
Equities	**93**	**-**	**-**	**93**
Fixed income	**-**	**78**	**-**	**78**
Real estate and infrastructure	**-**	**-**	**53**	**53**
Private equity	**-**	**-**	**3**	**3**
	94	**78**	**56**	**228**

15. EMPLOYEE FUTURE BENEFITS (continued)

2021	Level 1	Level 2	Level 3	Total
($ millions)				
Cash	1	-	-	1
Equities	106	-	-	106
Fixed income	-	100	-	100
Real estate and infrastructure	-	-	53	53
Private equity	-	-	3	3
	107	100	56	263

The following table is a reconciliation of changes in the fair value of defined benefit pension plan assets that have been measured using Level 3 inputs for the years ended December 31:

($ millions)	**2022**	2021
Balance, beginning of year	**56**	49
Actual return on plan assets relating to assets still held at the reporting date	**3**	7
Purchases, sales and settlements	**(3)**	-
Balance, end of year	**56**	56

Significant Actuarial Assumptions

The significant weighted average actuarial assumptions used to determine the projected benefit obligation and the net benefit cost are as follows:

	Defined Benefit Pension and Supplemental Plans		**OPEB Plans**	
($ millions)	**2022**	2021	**2022**	2021
Projected benefit obligation				
Discount rate as at December 31	**5.25%**	3.00%	**5.25%**	3.00%
Rate of compensation increase	**3.00%**	3.00%	**-**	-
Net benefit cost				
Discount rate as at January 1	**3.00%**	2.75%	**3.00%**	2.75%
Expected rate of return on plan assets	**6.40%**	5.70%	**-**	-
Health care cost trend rate as at December 31[1]	**-**	-	**5.00%**	5.00%

[1] Ultimate health care cost trend rate was reached in 2018.

15. EMPLOYEE FUTURE BENEFITS (continued)

The following table provides the components of and changes in the regulatory assets during the year that would otherwise have been recognized in other comprehensive income and AOCI and have not yet been recognized as components of periodic net benefit cost. The total unrecognized actuarial losses and past service costs for pension and OPEB that was recognized as a regulatory liability was $8 million (2021 - $33 million regulatory asset).

	Defined Benefit Pension and Supplemental Plans		OPEB Plans	
($ millions)	**2022**	2021	**2022**	2021
Regulatory asset, beginning of year	**39**	48	**(6)**	(5)
Net actuarial gains	**(31)**	(7)	**(10)**	(1)
Amortization of actuarial losses	**(1)**	(3)	**-**	-
Amortization of past service credit	**1**	1	**-**	-
Regulatory asset (liability), end of year (note 8)	**8**	39	**(16)**	(6)

Funding Contributions

Under the terms of the defined benefit pension plans, the Corporation is required to provide pension funding contributions, including current service, solvency and special funding amounts. The Corporation's estimated 2023 contributions are $3 million (December 31, 2022 - $4 million).

The Corporation's estimated 2023 OPEB contributions are $1 million (December 31, 2022 - $1 million).

Benefit Payments

The following table provides the amount of benefit payments expected to be made over the next 10 years.

(*$ millions*)	Defined Benefit Pension and Supplemental Plans	OPEB Plans
2023	**10**	**1**
2024	**10**	**1**
2025	**11**	**1**
2026	**11**	**1**
2027	**11**	**1**
2028-2032	**61**	**4**
	114	**9**

16. REVENUE

Disaggregation of Revenue

The following table presents the disaggregation of the Corporation's revenue by type of customer for the years ended December 31:

($ millions)	**2022**	2021
Residential	**214**	205
Commercial	**113**	110
Wholesale	**54**	52
Industrial	**47**	38
Total electricity revenue	**428**	405
Other contract revenue [1]	**60**	52
Total revenue from contracts with customers	**488**	457
Alternative revenue [2]	**(30)**	(18)
Other revenue [3]	**16**	15
Total revenue	**474**	454

[1] Other contract revenue includes utility customer connection fees, surplus power sales, revenue from third party contract work and pole attachments, and revenue from the sale of carbon credits.

[2] Alternative revenue includes the Earnings Sharing Mechanism, which recognizes the 50/50 sharing of variances from the allowed ROE, and flow-through variances related to tariff-based revenue.

[3] Other revenue is primarily comprised of other flow-through and regulatory deferral adjustments resulting from cost recovery variances in regulated forecasts used to set rates for electricity revenue.

17. FINANCE CHARGES

($ millions)	**2022**	2021
Interest on long-term debt	**42**	41
Interest on short-term debt	**2**	1
Debt component of AFUDC (note 6)	**(1)**	(1)
Net interest on debt	**43**	41
Interest on finance leases (note 12)	**33**	32
Total finance charges	**76**	73

18. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

The supplementary information to the Consolidated Statements of Cash Flows for the years ended December 31 are as follows:

($ millions)	**2022**	2021
Interest paid	**40**	41
Net income tax paid	**15**	-

Change in working capital		
Accounts receivable and other current assets	**(2)**	(6)
Prepaid expenses	**(1)**	-
Accounts payable and other current liabilities	**(1)**	12
Total change in working capital	**(4)**	6

18. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

Non-Cash Investing Activities

($ millions)	**2022**	2021
As at December 31		
Accrued capital expenditures	**25**	25

19. INCOME TAXES

Deferred Income Tax

The significant components of deferred income tax assets and liabilities consisted of the following as at December 31:

($ millions)	**2022**	2021
Deferred income tax liability (asset)		
Property, plant and equipment	**223**	208
Intangible assets	**16**	15
Regulatory assets	**16**	15
Regulatory liabilities	**(8)**	(4)
Debt issuance costs	**1**	1
Employee future benefits	**(5)**	(6)
Other	**(3)**	(3)
Net deferred income tax liability	**240**	226

As at December 31, 2022 and 2021, the Corporation has no non-capital losses carried forward.

Provision for Income Taxes

($ millions)	**2022**	2021
Current income tax expense	**12**	11
Deferred income tax expense	**13**	15
Regulatory adjustment (note 8)	**(13)**	(15)
Deferred income tax expense, net of regulatory adjustment	**-**	-
Income tax expense	**12**	11

Variation in Effective Income Tax Rate

Income taxes vary from the amount that would be computed by applying the Canadian federal and BC combined statutory income tax rate of 27.0 per cent (2021 – 27.0 per cent) to earnings before income taxes as shown in the following table for the years ended December 31:

	2022	2021
Combined statutory income tax rate	**27.0%**	27.0%
($ millions)		
Statutory income tax rate applied to earnings before income taxes	**20**	18
Items capitalized for accounting but expensed for income tax purposes	**(3)**	(3)
Difference between capital cost allowance and amounts expensed for accounting purposes	**(8)**	(8)
Difference between employee future benefits paid and amounts expensed for accounting purposes	**(1)**	-
Difference between regulatory accounting items and amounts claimed for tax purposes	**4**	4
Actual income tax expense	**12**	11
Effective income tax rate	**16.1%**	16.5%

19. INCOME TAXES (continued)

Taxation years 2017 and prior are no longer subject to examination in Canada. An examination of the open tax years subsequent to 2017 by the Canada Revenue Agency could result in a change in the liability for unrecognized tax benefits.

20. FINANCIAL INSTRUMENTS

The Corporation categorizes financial instruments into the three-level hierarchy based on inputs used to determine the fair value:

Level 1: Fair value determined using unadjusted quoted prices in active markets;
Level 2: Fair value determined using pricing inputs that are observable; and
Level 3: Fair value determined using unobservable inputs only when relevant observable inputs are not available.

Financial Instruments Not Carried At Fair Value

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. The Corporation uses the following methods and assumptions for estimating the fair value of financial instruments:

- The carrying values of cash, accounts receivable, accounts payable, other current assets and liabilities and borrowings under credit facilities on the Consolidated Balance Sheets of the Corporation approximate their fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.

- For long-term debt, the Corporation uses quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs.

The use of different estimation methods and market assumptions may yield different estimated fair value amounts. The following table includes the carrying value, excluding unamortized debt issuance costs and including current and long-term portions, and estimated fair value of the Corporation's long-term debt as at December 31:

		2022		2021	
($ millions)	Fair Value Hierarchy	**Carrying Value**	**Estimated Fair Value**	Carrying Value	Estimated Fair Value
Long-term debt	Level 2	**885**	**813**	785	979

Power purchase contracts that have been designated as normal purchase or normal sale contracts are not reported at fair value under the accounting rules for derivatives. They are accounted for on an accrual basis.

21. CREDIT FACILITIES

As at December 31, 2022, the Corporation had a $150 million operating credit facility in place, which matures in April 2027, and a $10 million demand overdraft facility.

The weighted average interest rate on borrowings under the Corporation's operating credit facility at December 31, 2022, was approximately 4.36 per cent (December 31, 2021 – 0.14 per cent).

The following summary outlines the Corporation's credit facilities as at December 31:

($ millions)	**2022**	2021
Operating credit facility	**150**	150
Demand overdraft facility	**10**	10
Draws on operating credit facility	**(63)**	(115)
Draws on overdraft facility	**(2)**	(1)
Credit facilities available	**95**	44

22. RELATED PARTY TRANSACTIONS

In the normal course of business, the Corporation transacts with its parent, FortisBC Pacific, its ultimate parent, Fortis, and other related companies under common control, including FEI and FortisBC Holdings Inc. ("FHI"). The following transactions were measured at the exchange amount unless otherwise indicated.

Related Party Recoveries

The amounts charged to the Corporation's parent and other related parties under common control for the years ended December 31 were as follows:

($ millions)	**2022**	2021
Operating costs charged to FortisBC Pacific (a)	**8**	7
Operating costs charged to FEI (b)	**7**	6
Operating costs charged to FHI (c)	**1**	1
Total related party recoveries	**16**	14

(a) The Corporation charged its parent, FortisBC Pacific, for management services, labour, and materials.

(b) The Corporation charged FEI for electricity sales, management services, and other labour.

(c) The Corporation charged FHI for management services and other labour.

Related Party Costs

The amounts charged by related parties under common control for the years ended December 31 were as follows:

($ millions)	**2022**	2021
Operating costs charged by FEI (a)	**8**	7
Operating costs charged by FHI (b)	**5**	5
Total related party costs	**13**	12

(a) FEI charged the Corporation for natural gas purchases, office rent, management services, and other labour.

(b) FHI charged the Corporation for management services and governance costs.

22. RELATED PARTY TRANSACTIONS (continued)

Balance Sheet Amounts

The amounts due from related parties, included in accounts receivable and other current assets on the Consolidated Balance Sheets, and the amounts due to related parties, included in accounts payable and other current liabilities on the Consolidated Balance Sheets, were as follows as at December 31:

	2022		2021	
($ millions)	**Amount Due From**	**Amount Due To**	Amount Due From	Amount Due To
FPHI	**-**	**-**	1	**-**
Fortis	**-**	**-**	1	**-**
FEI	**-**	**-**	-	(1)
FHI	**-**	**(1)**	-	(1)
Total (due to) due from related parties	**-**	**(1)**	2	(2)

23. COMMITMENTS

The following table sets forth the Corporation's estimated commitments due in the years indicated:

As at December 31, 2022	**Total**	**Due within 1 Year**	**Due in Year 2**	**Due in Year 3**	**Due in Year 4**	**Due in Year 5**	**Due after 5 Years**
($ millions)							
Power purchase obligations (a)	**2,751**	103	92	89	88	86	2,293
Finance lease obligations (note 12)	**1,175**	34	34	35	35	36	1,001
Long-term debt[1] (note 11)	**885**	25	-	-	-	-	860
Interest obligations on long-term debt (note 11)	**910**	42	40	40	40	40	708
Other (b)	**6**	4	1	1	-	-	-
Total	**5,727**	208	167	165	163	162	4,862

[1] Excludes unamortized debt issuance costs.

(a) In addition to the BPPA, which has been recognized as a finance lease obligation (note 12), the Corporation's power purchase obligations consist of the following:

Waneta Expansion Capacity Agreement ("WECA")

In 2010, FBC entered into an agreement to purchase capacity from the Waneta Expansion, a 335 MW hydroelectric generating facility adjacent to the existing Waneta Plant on the Pend d'Oreille River in BC. The WECA, which was accepted by the BCUC in May 2012, allows FBC to purchase capacity over 40 years, beginning April 1, 2015.

BC Hydro Power Purchase Agreement ("BCH PPA")

In 2013, FBC entered into the BCH PPA to purchase up to 200 MW of capacity and 1,752 Gigawatt hours per year of associated energy for a 20 year term beginning October 1, 2013. The BCH PPA was approved by the BCUC in May 2014 and was effective July 1, 2014. The capacity and energy to be purchased under this agreement do not relate to a specific plant. The BCH PPA meets the exemption for normal purchases and as such is not required to be recorded at fair value as a derivative.

23. COMMITMENTS (continued)

Capacity and Energy Purchase and Sale Agreement ("CEPSA")

In 2015, FBC entered into the CEPSA which allows FBC to purchase all of its market energy requirements from Powerex and for FBC to sell any surplus capacity to Powerex that may be available after FBC meets its load requirements. The CEPSA was accepted by the BCUC in April 2015 and became effective beginning May 2015. As at December 31, 2022, the total power purchase commitments outstanding under the CEPSA were approximately $3 million through to the second quarter of 2023. The energy purchases under the CEPSA do not relate to specific plants and the output being purchased does not constitute a significant portion of the output of a specific plant.

Brilliant Expansion Capacity and Energy Purchase Agreement

In 2017, FBC entered into an agreement to purchase capacity and energy from CPC, acting on behalf of the Brilliant Expansion Power Corporation, from January 2018 through to December 2027. The agreement was accepted by the BCUC in October 2017.

(b) Included in other commitments are operating leases, defined benefit pension plan funding obligations, and an asset retirement obligation.

In addition to the items in the table above, the Corporation has issued commitment letters to customers who may meet the criteria to obtain energy efficiency funding under the DSM Expenditures Plan approved by the BCUC. As at December 31, 2022, the Corporation had issued $5 million (December 31, 2021 - $6 million) of commitment letters to these customers.

Diane Roy
Vice President, Regulatory Affairs

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August 5, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2023 Rates

In accordance with the MRP Plan and BCUC Order G-193-22 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2023 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FBC Annual Review for 2022 Rates

FORTISBC INC.

Annual Review for 2023 Rates

August 5, 2022

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10 of the Application, FBC proposes to distribute $0.911 million pre-tax ($0.665 million after-tax) in earnings sharing to customers in 2023.

The proposed rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 3.99 percent rate increase from 2022 rates. The increase is primarily due to an increase in power purchase expense (PPE) as well as rate base growth.

In the subsections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FBC's 2021 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.
2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.

3. The following deferral account approvals, as described in Section 7.6:

   - Creation of a rate base deferral account for the 2023 Joint Pole Use Audit, with the balance in the deferral account to be amortized over five years commencing January 1, 2023; and
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.

4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.6.2.1.

FBC also seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 6 of Order G-42-21 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FBC continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10

Item	Description	Response or Reference
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.4 million.

Approximately $0.9 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. Lower spending in the Finance and Information Systems departments of approximately $0.6 million from vacancies, reduced consulting, and lower computer consulting services and expenses contributed to the savings. Additionally, approximately $2.2 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. These savings were partially offset by approximately $0.3 million of higher spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security. Please refer to Section 6.2.1 for further details. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FBC's Annual Review for 2022 Rates (2022 Annual Review), in 2021, FortisBC Energy Inc. (FEI) and FBC (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Field Operations Improvements:** This initiative was investigated through collecting feedback and analyzing efficiency gains within FBC's Outage Management System (OMS) and Mobile Workforce Management System (MWFM). Changes have been made to the software and processes that allow for improved information sharing and functionality when dispatching and performing jobs. This allows for less manual intervention and a more streamlined workflow. On a separate, but related initiative, enhancements are also underway to provide FBC's storm response restoration teams with an improved interface to access triage information. This will allow for a better prioritization of repairs, and a more efficient allocation of the available resources, resulting in faster restorations.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC is investigating using UAVs to perform transmission line condition assessments. In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies. This use of drones was expected to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from the ground, and allow FBC to prepare work-packages for deficiencies identified during condition assessments in a more timely manner. Additionally, some of the drone-collected data has been used to help assess potential system upgrades and reconfigurations without requiring additional field verification of existing assets. For 2022, FBC is developing a request for pricing to assess the potential efficiencies associated with a condition assessment program relying exclusively on drone-collected data and the use of artificial intelligence and machine learning to help identify and categorize deficiencies related to FBC's transmission assets. Should a proponent be identified through this process, it is expected that this work will help validate the use of these techniques for performing condition assessment work and also help quantify the potential cost-savings associated with a drone-based approach for condition assessments.

3. **Technology Investments to Support Enhanced Communications:** FBC introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FBC also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition

from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, FBC invested approximately $0.2 million over the two years 2020 and 2021. This investment has contributed to achieving employee-related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to costs or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FBC is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is

used to integrate, transform and format reports. FBC is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FBC will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FBC will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FBC had approximately 69,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 8,000 customers choosing this option in 2021. This increase equates to approximately $0.07 million in printing and postage cost savings in 2021 as compared to 2020.[1]

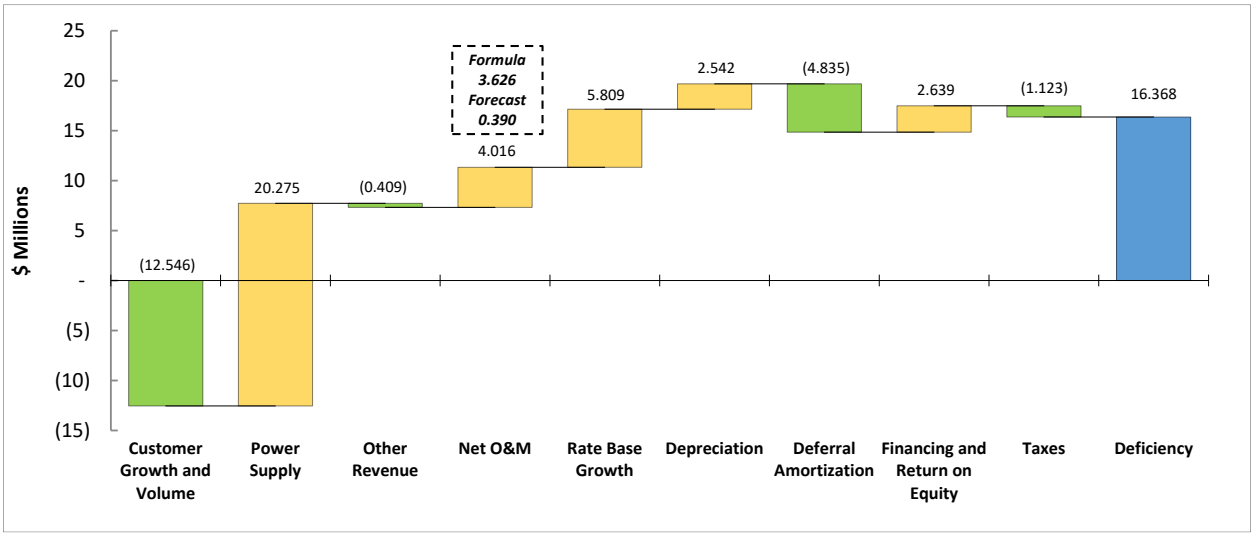
[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.24 per bill.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2023*

The revenue requirement components set out in the Application result in an effective rate increase of 3.99 percent for 2023 compared to 2022. The effective rate increase results from a revenue deficiency of $16.368 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $16.368 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million. The increase in net load is primarily due to increased loads in the industrial classes, followed by smaller increases in the residential, commercial, wholesale, and irrigation classes. FBC's 2023 Forecast revenue at 2022 approved rates is $409.840 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved. This increase is primarily due to the increase in load, and an increase in PPE under the BC Hydro Power Purchase Agreement (PPA) by approximately $27.240 million. This is offset by reduced market and contracted purchases by approximately $8.776 million.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase by $0.409 million in 2023 compared to 2022 Approved. The main drivers of this increase are higher Late Payment Charges and the expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

1.5.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 4.017 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers[2]. The 2023 Formula O&M net of capitalized overhead has increased by $3.626 million[3] when compared to the 2022 Formula O&M. Net O&M forecast outside of the formula is increasing by $0.390 million[4] over 2022 Approved, primarily due to an increase in pension and OPEB expense. Overall, the 2023 increase in total O&M expense net of capitalized overhead is $4.016 million (6.9 percent).

1.5.5 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $92.524 million when compared to the 2022 Approved rate base, resulting in an increase to the 2023 revenue deficiency of $5.809 million. The increase in rate base is primarily the result of the mid-year impact of FBC's 2023 regular capital additions to plant, as well as the full-year impact of FBC's major capital project additions, including the Kelowna Bulk Transformer Additions (KBTA) project, the Corra Linn Dam Spillway Gates Replacement project, and the Playmor Substation Upgrade project, as described in Section 7.1.

The increase in rate base also results in an increase in 2023 depreciation expense by approximately $2.752 million compared to 2022 Approved, which is offset by approximately $0.210 million of CIAC from net additions, resulting in a net increase of $2.542 million in depreciation expense.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 decreased by $4.835 million, primarily due to the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account, partially offset by increases in the amortization expense of the DSM deferral account, the BCUC Initiated Inquiry Costs deferral account, and the COVID-19 Customer Recovery Fund deferral account. The credit amortization in the Flow-through deferral account in 2023 is $9.625 million, which is $5.698 million higher than the credit amortization in this account compared to 2022 Approved. As discussed in Section 12.4.2.1, the credit amortization in the Flow-through deferral account is

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $3.810 million (5.8 percent) compared to 2022 Approved.
[4] Increase in gross forecast O&M of $0.491 million (26.8 percent) compared to 2022 Approved.

primarily due to favourable revenue variances resulting from increased loads from industrial, commercial, wholesale, and residential classes.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.639 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2023, FBC is forecasting a short-term debt rate of 4.24 percent, which is an increase from the 1.51 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, FBC's deficiency is increased by $3.688 million from financing rate changes which is offset by $1.049 million from the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FBC has utilized its currently approved capital structure and ROE of 40 percent and 9.15 percent, respectively. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

1.5.8 Taxes (Section 9)

FBC's 2023 property taxes are forecast to increase by 2.1 percent or $0.371 million from 2022 Approved. The increase is primarily due to changes in tax rates and increases in assessed values, as well as an increase in grants in-lieu of taxes which are calculated based on a fixed percentage of FBC's revenue.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by $1.494 million due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 *INTRODUCTION AND OVERVIEW*

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2023 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and determined that a growth factor multiplier of 75 percent for formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2023, FBC has used July 2020 through June 2022 inflation data for the 2023 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

2.2 *INFLATION FACTOR CALCULATION SUMMARY*

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2021 labour weighting of 60 percent, the calculation of the 2023 I-Factor is (4.940 percent x 40 percent) + (4.235 percent x 60 percent) = 4.517 percent.

[5] FBC's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.
[6] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	40%	60%	4.517%	2023

2.3 GROWTH FACTOR CALCULATION SUMMARY

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M.

The calculation of average customers used to determine 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,861		Appendix A2 - Section 3.1 Customers
2							
3	Additions:						
4	January	292	257	226	256		
5	February	174	89	194	266		
6	March	8	123	122	264		
7	April	110	113	178	264		
8	May	173	319	537	255		
9	June	172	116	250	261		
10	July	522	308	255	265		
11	August	129	187	252	262		
12	September	83	136	254	264		
13	October	545	132	255	265		
14	November	234	217	252	262		
15	December	245	119	256	266		
16	Total Additions	2,687	2,116	3,031	3,150		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,587	1,701		
18							
19	Current Year Ending Customer Count	143,714	145,830	148,861	152,011		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20							
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,417		2020: G-42-21; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	142,321	144,877	147,417	150,562		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,540	3,145	**10,646**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes					**7,985**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**147,901**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		142,473				2021: G-42-21; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		143,637				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**1,164**				Line 32 - Line 31

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M for 2023 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.		2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	40%	Table 2-1, Line 24
5	Labour	60%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.517%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	4.017%	Line 7 + Line 9
12			
13	Average Customers for Formula O&M purposes	147,901	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2023 is 4.017 percent and formula O&M for 2023 is determined using average customers of 147,901.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting an increase in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F gross load is forecast to be approximately 3,775 GWh, which is a 184 GWh increase compared to the 2022 Approved gross load. The increase in 2023F is due to increased loads in the industrial, commercial, wholesale, residential and irrigation classes. Based on the 2022 Approved rates for each customer class, FBC's 2023 revenue forecast is $409.840 million.

FBC has provided further information supporting its load forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the UPC forecast is multiplied by the corresponding forecast of the number of annual average customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2022 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 *DEMAND SIDE MANAGEMENT SAVINGS*

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2021.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast incremental DSM savings for 2023 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2023 DSM Savings (GWh)

Line No.	Description	DSM 2023
1	Residential	(8.9)
2	Commercial	(22.6)
3	Wholesale	(7.7)
4	Industrial	(16.2)
5	Lighting	(0.3)
6	Irrigation	(0.2)
7	Net	(55.9)
8	Losses	(4.6)
9	Gross Load	(60.5)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized residential, commercial and wholesale load and the actual industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2021 was 0.2 percent. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,476 GWh in 2023F, which is 3 GWh more than 2022S and an increase of 170 GWh from 2022 Approved.

Figure 3-1: Total Net Load (GWh)

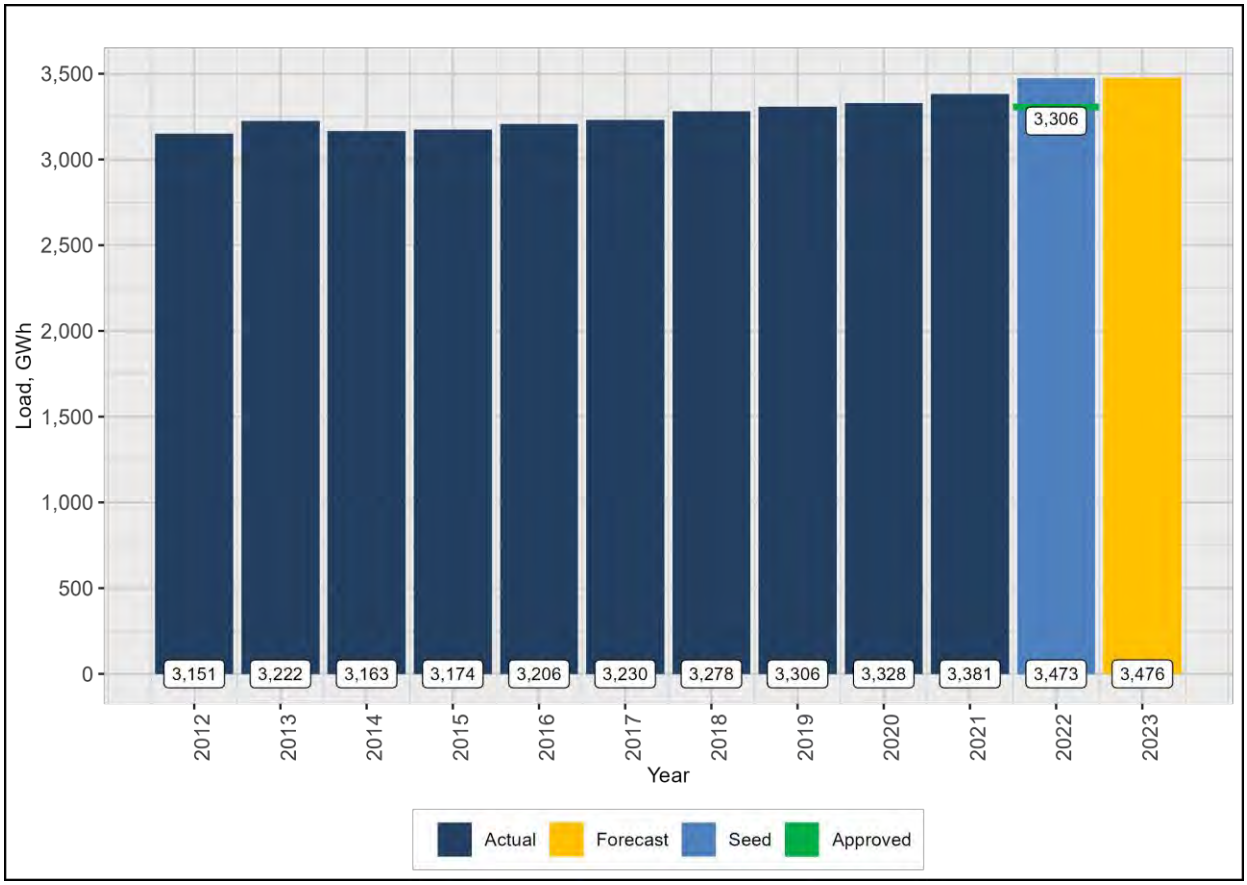


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2023F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: Normalized After-Savings Gross Load and System Peak

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
	Energy (GWh)												
1	Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
2	Commercial	681	788	863	853	905	915	926	932	922	960	962	973
3	Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
4	Industrial	291	352	381	380	373	363	403	495	441	472	579	575
5	Lighting	13.5	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.5	9.4
6	Irrigation	38.0	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	39.5	39.4
7	Net Load	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
8	Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
9	Gross Load	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
10													
11	System Peak (MW)												
12	Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
13	Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

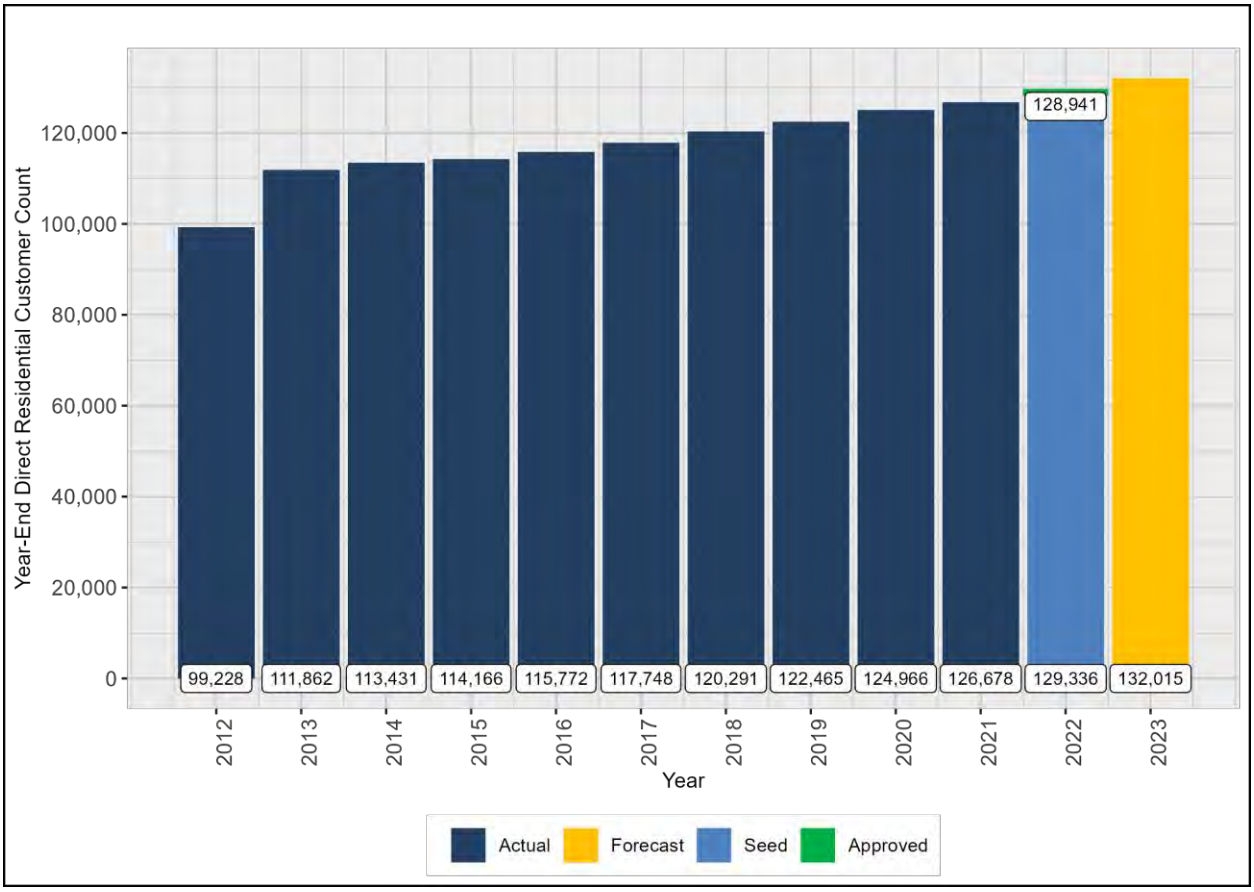
3.4.1 Residential

3.4.1.1 Residential Customers

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

Figure 3-2 shows the year-end residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count

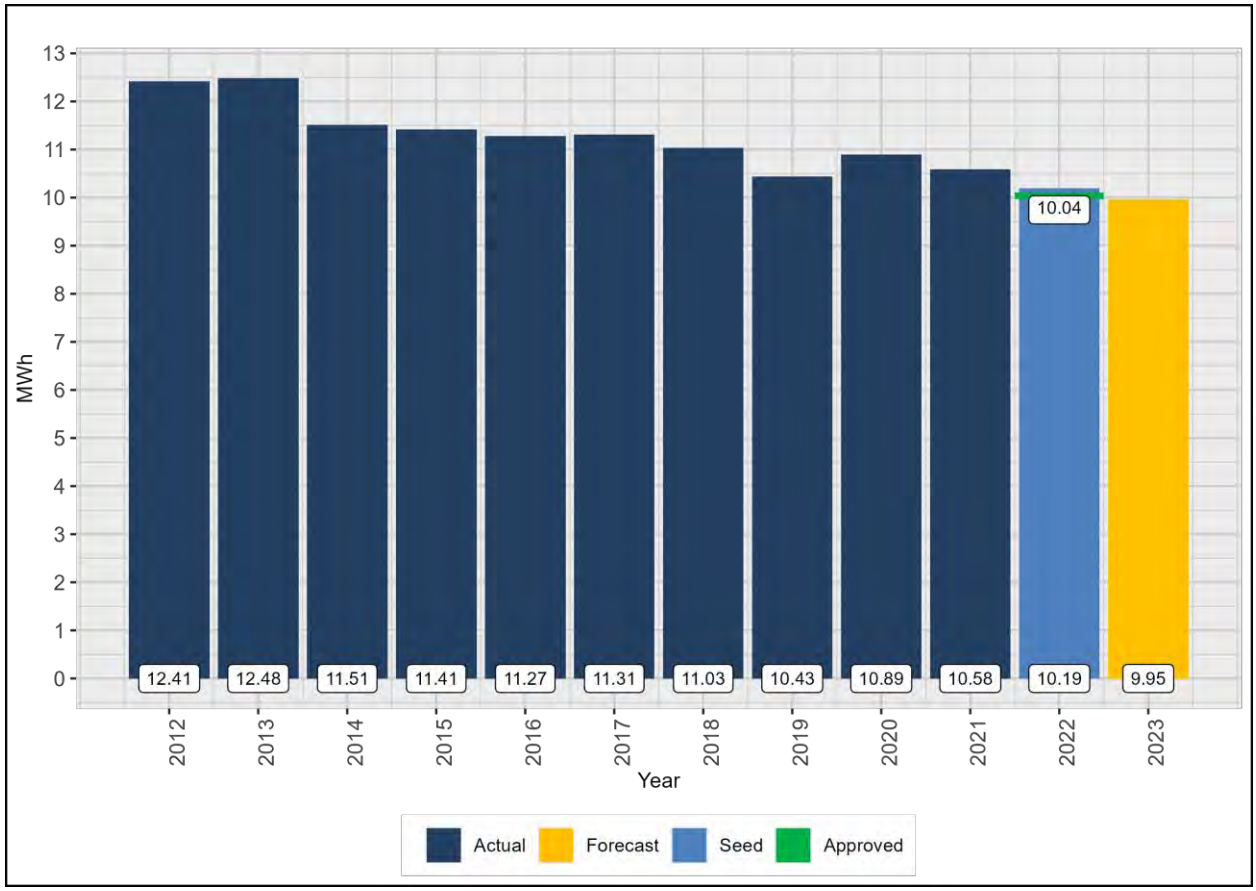


3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a 10-year trend to the normalized historical UPCs. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2021, are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average

customer count. As shown in Figure 3-3 below, the residential after-savings UPC is forecast to decrease by 0.24 MWh in 2023F from 2022S and decrease by 0.09 MWh from 2022 Approved.

Figure 3-3: Normalized After-Savings Residential UPC (MWh)

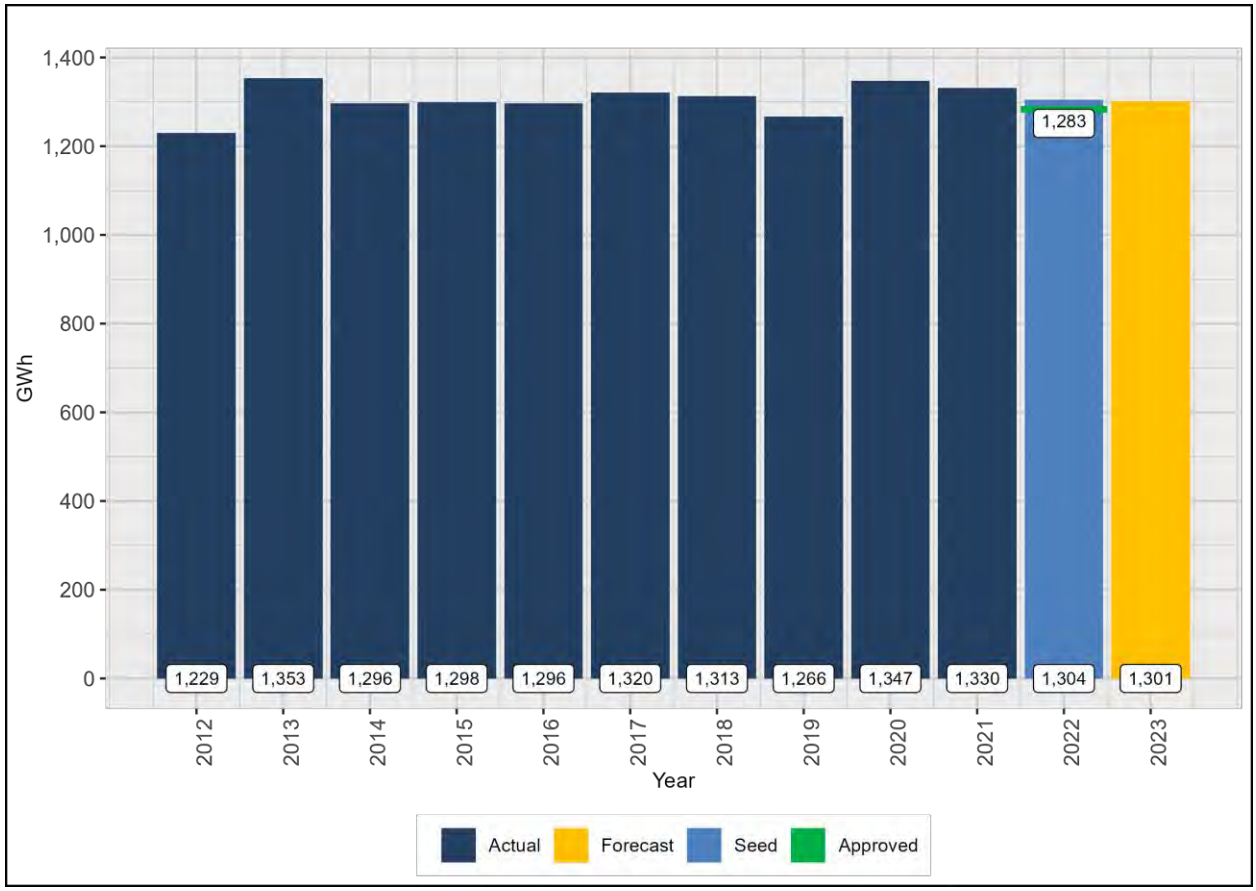


3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings.

As shown in Figure 3-4 below, residential after-DSM savings load is forecast to decrease by 3 GWh in 2023F from 2022S and increase by 18 GWh from 2022 Approved levels.

Figure 3-4: Normalized After-Savings Residential Load (GWh)

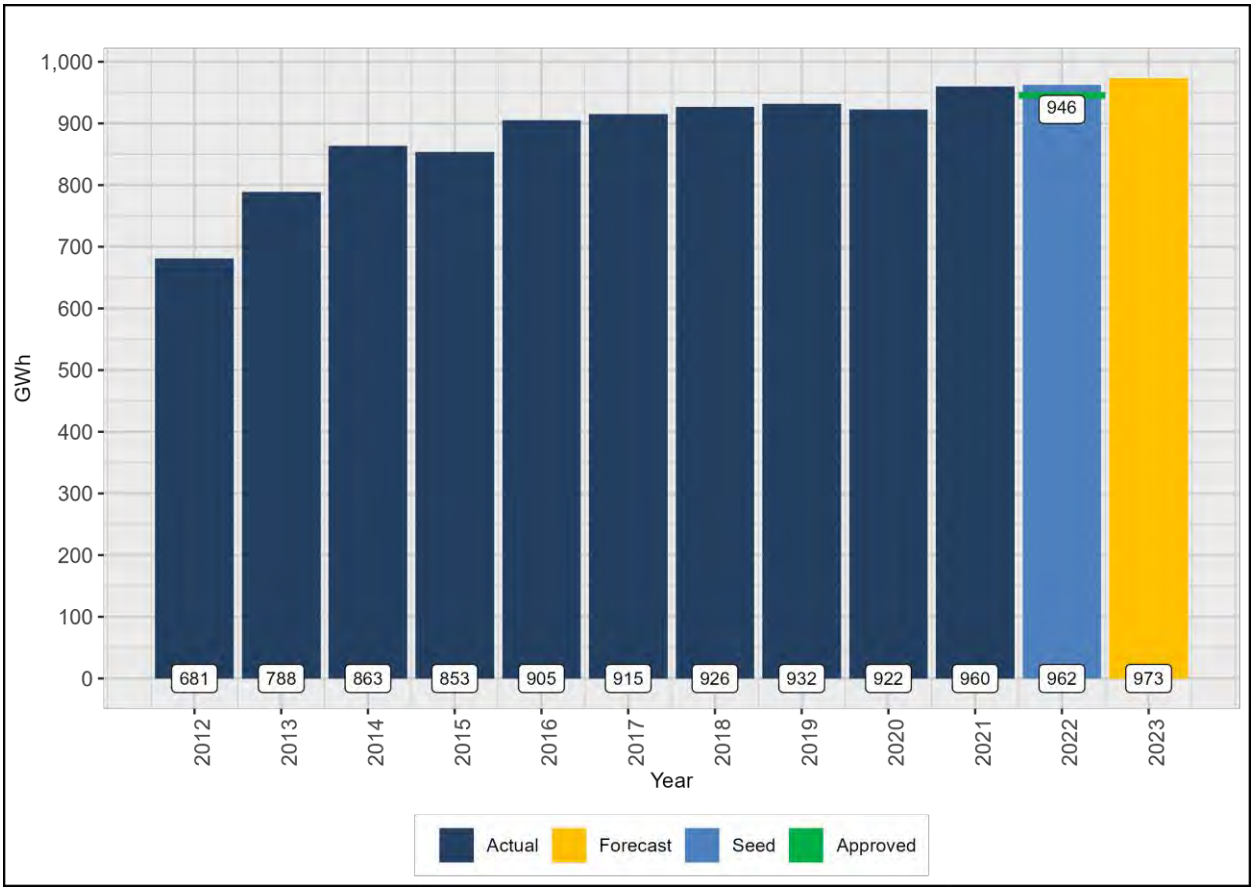


3.4.2 Commercial

3.4.2.1 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2022S and 2023F and account for less than a 1 GWh increase in both 2022S and 2023F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 11 GWh in 2023F from 2022S and increase by 27 GWh in 2023F from 2022 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2023, all but one of the wholesale customers responded with their load forecast projections.

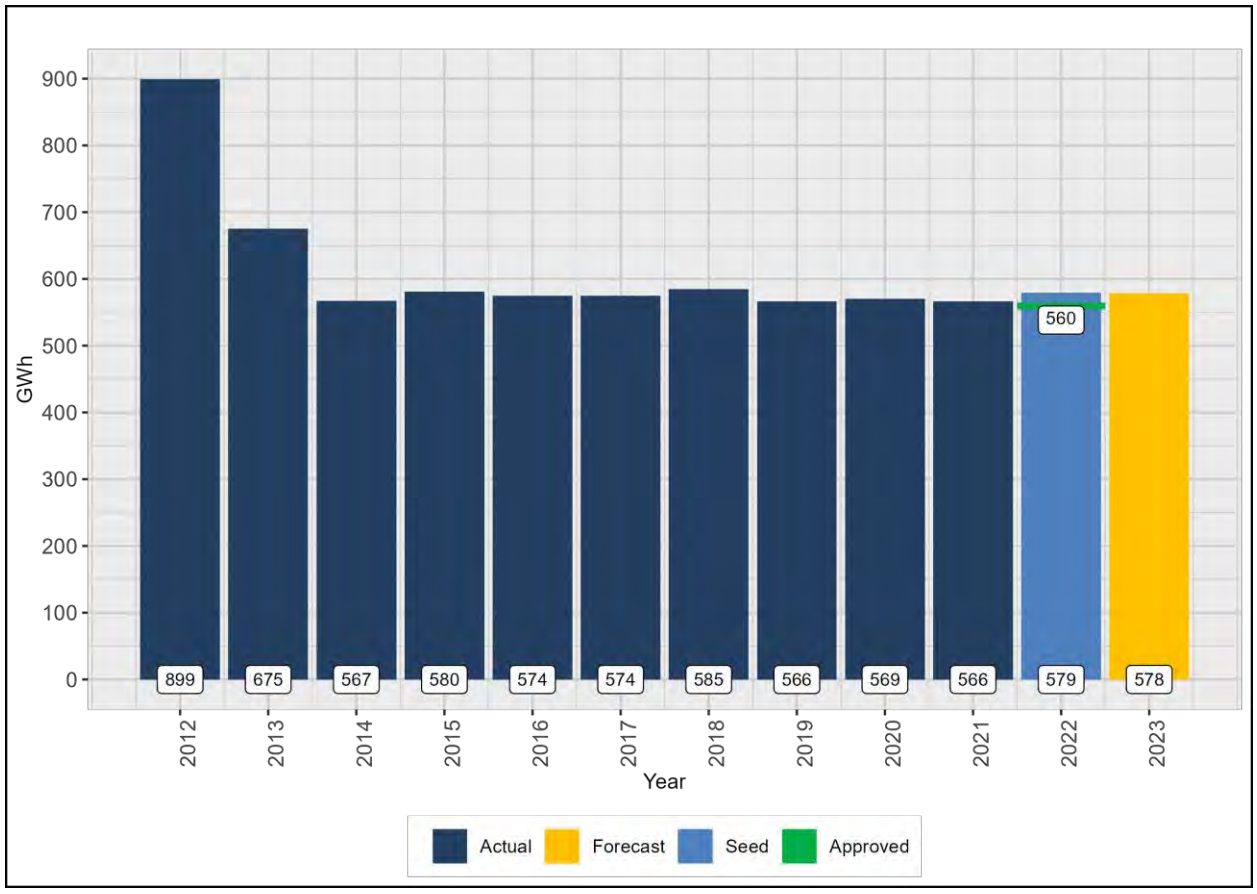
In the Annual Review for 2022 Rates Decision, the BCUC Panel directed FBC "to provide any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts."[8] The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts. As such, in April of this year, FBC met with the City of Penticton, the District of

[8] FBC Annual Review for 2022 Rates Decision and Order G-374-21, p. 32.

Summerland and the City of Nelson to discuss load forecast methods, techniques and tools, as well as each City's/District's individual load forecasts. Both FBC and the Cities/District found the workshops to be informative and productive, and FBC intends to continue to conduct these workshops on an annual basis in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 1 GWh in 2023F from 2022S and increase by 18 GWh in 2023F from 2022 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



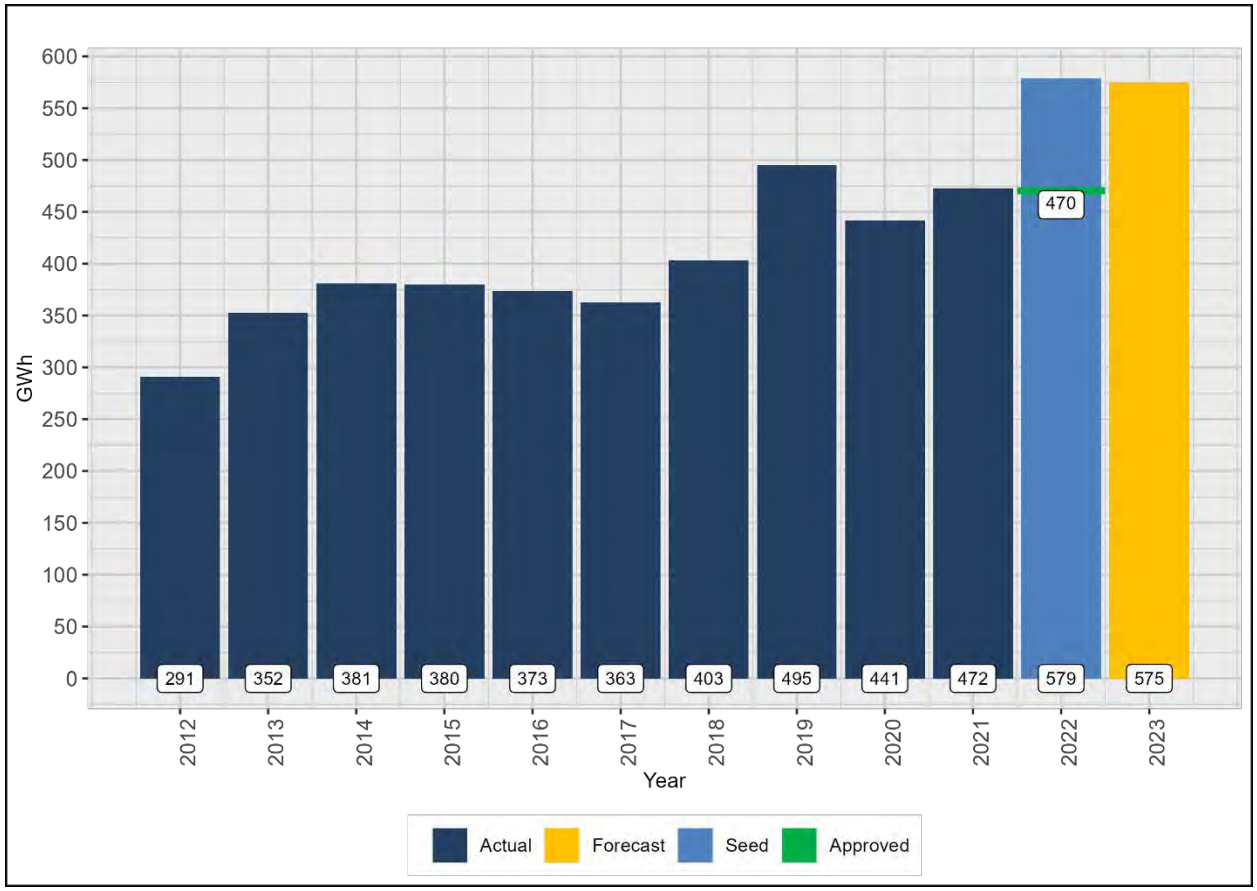
3.4.4 Industrial

Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 81 percent (34 of 42) of the surveys sent out. The responding customers represent approximately 90 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to decrease by 4 GWh in 2023F when compared to 2022S and increase by 105 GWh in 2023F compared to 2022 Approved. The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads.

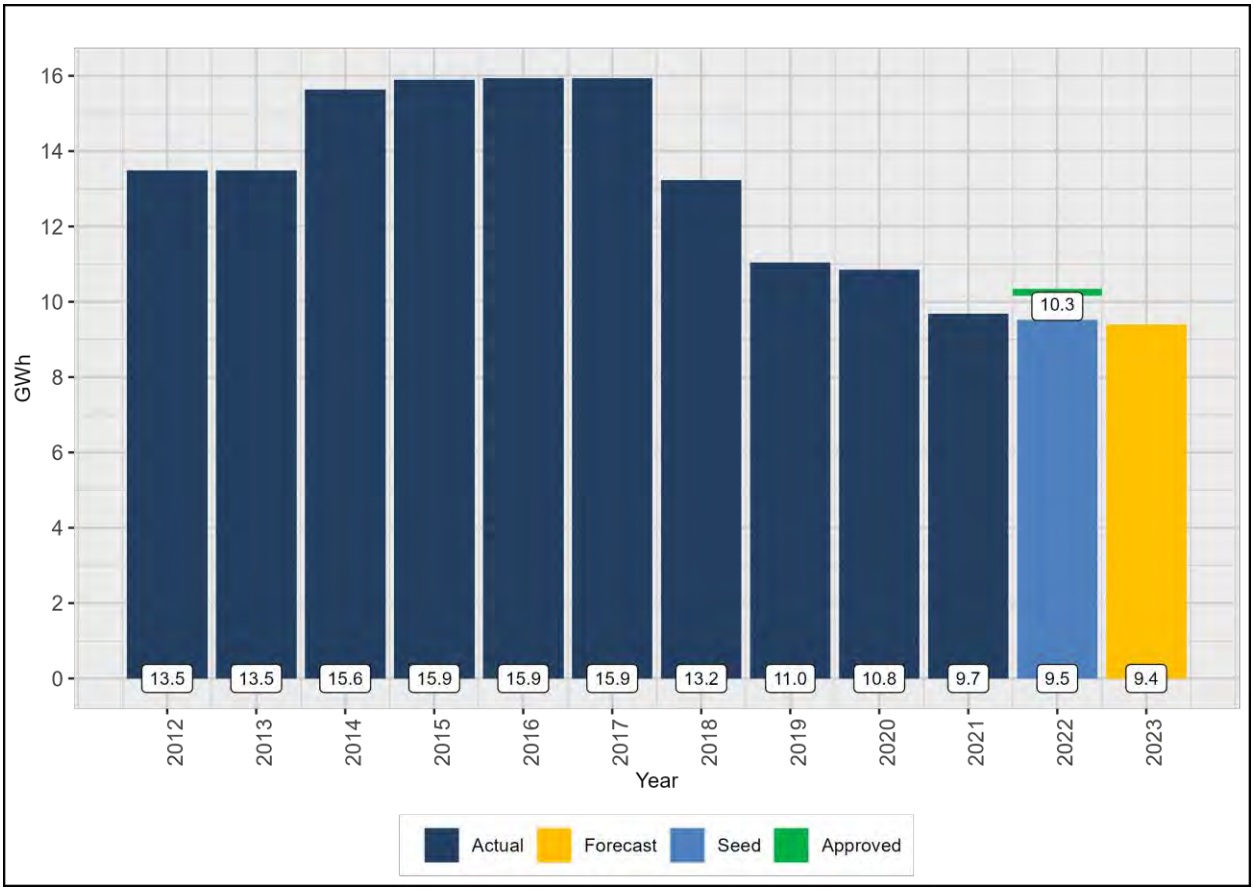
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has seen declines for the past four years. FBC used the 2021 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2023F from 2022S and decrease by 0.9 GWh when compared to 2022 Approved.

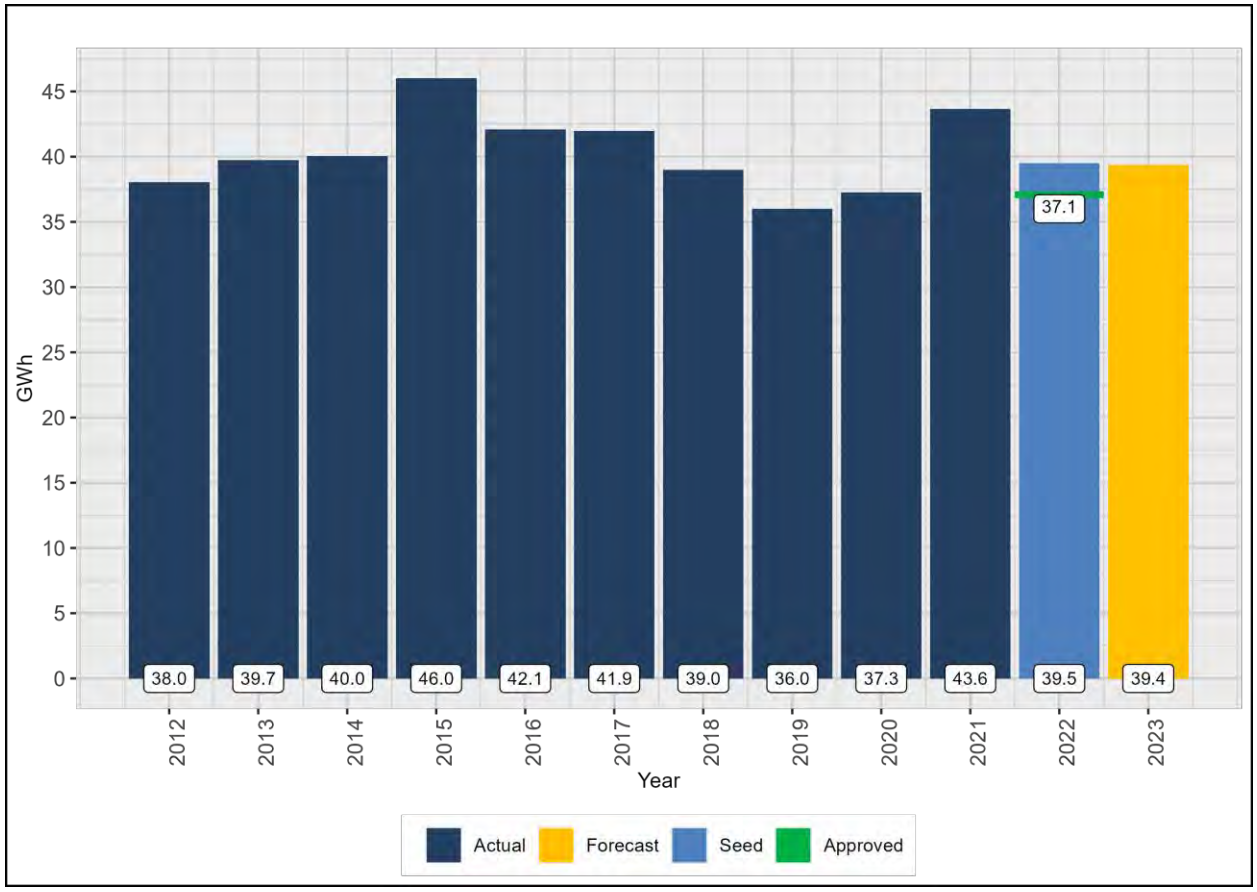
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease 0.1 GWh from 2022S to 2023F and increase by 2.3 GWh in 2023F when compared to 2022 Approved.

Figure 3-9: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

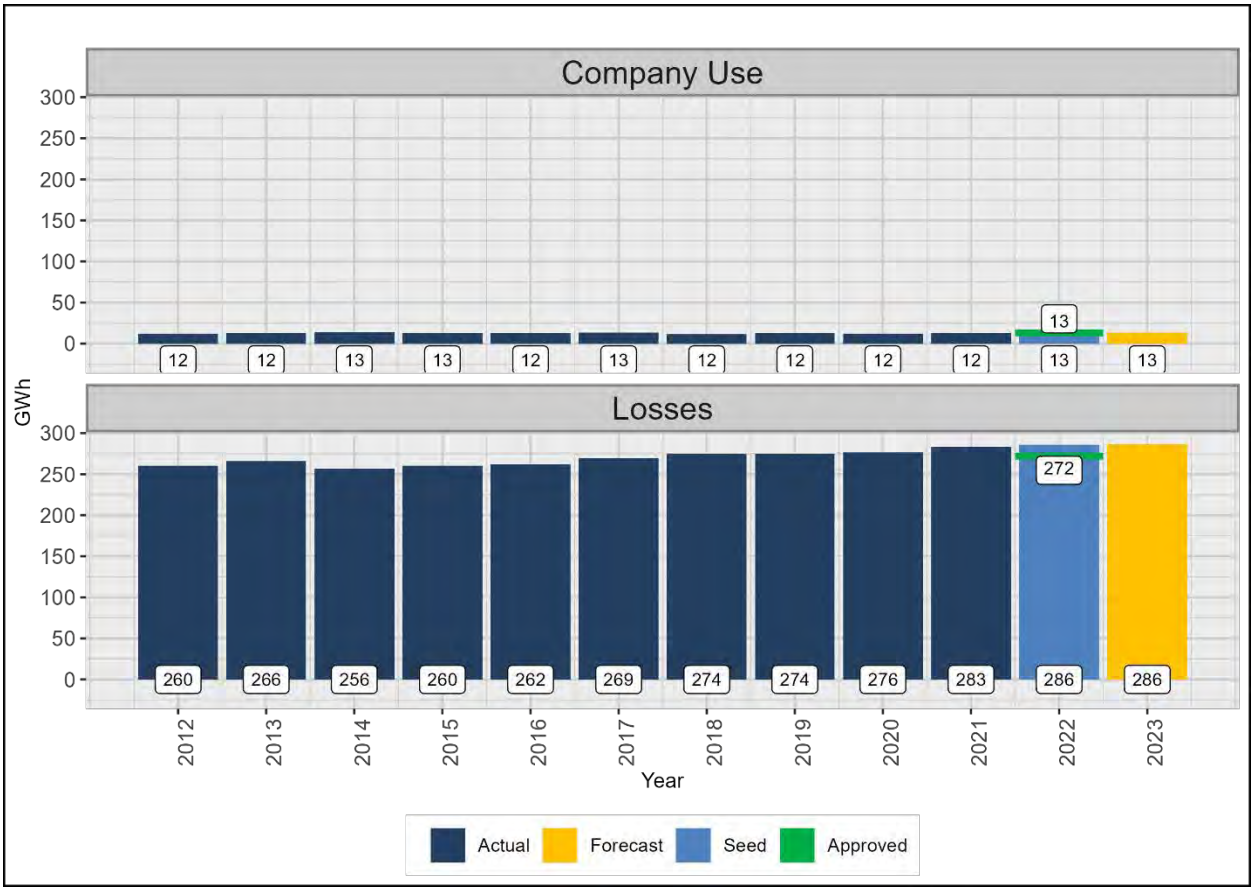
FBC conducted a Losses Study in 2019[9] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-10 below, after-savings load losses are forecast to remain constant in 2023F because the gross load is forecast to be relatively stable when compared to 2022S. When compared to 2022 Approved, the 2023F after-savings load losses are forecast to increase by 14 GWh due to increased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2023F, consistent with 2022S.

[9] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 "heat dome" event. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Normalized after-savings historical winter and summer peaks are shown below along with 2022S and 2023F. The peaks shown below are seasonal, where the winter peak can fall in either November or December of the current year or January and February of the following year, while the summer peak falls in June, July or August of the current year.

Figure 3-11: After-Savings Winter Peaks (MW)

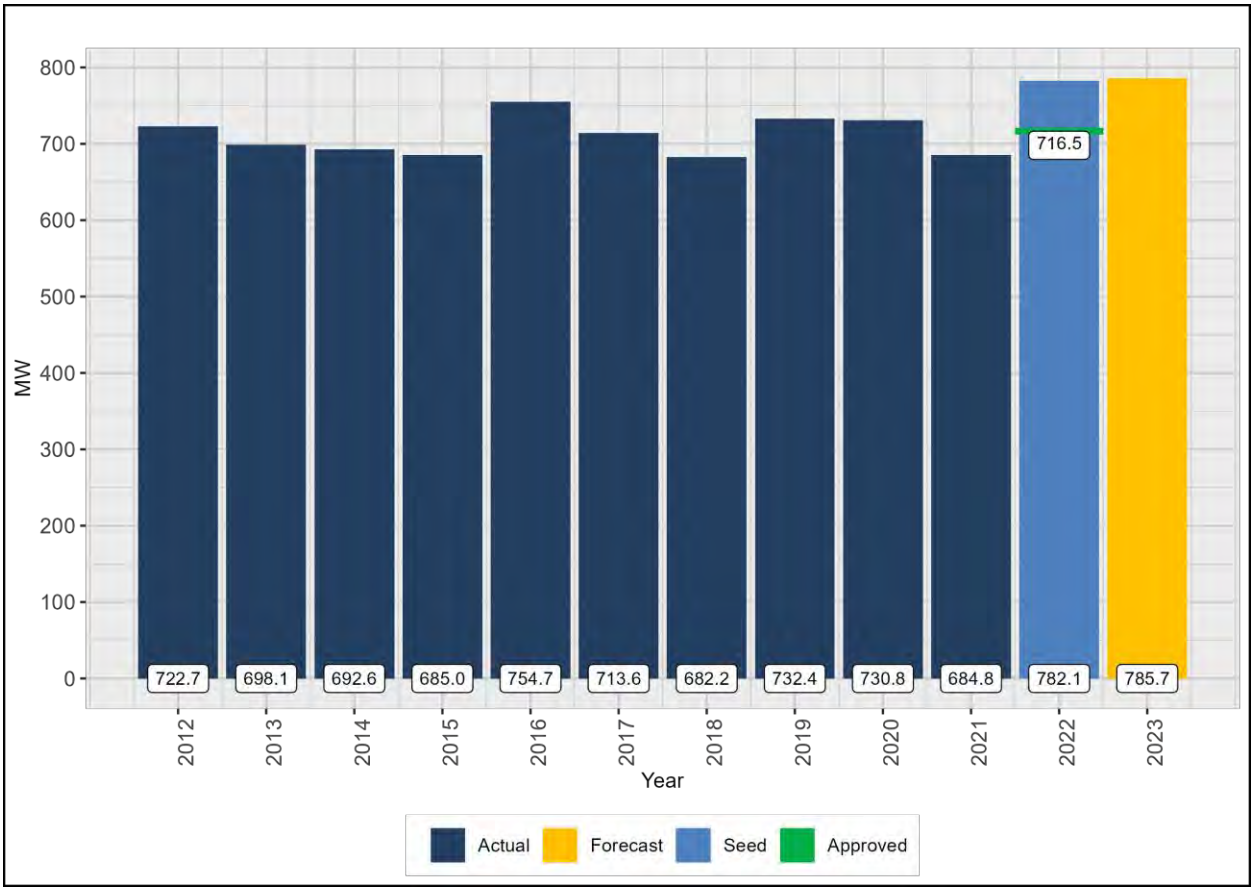
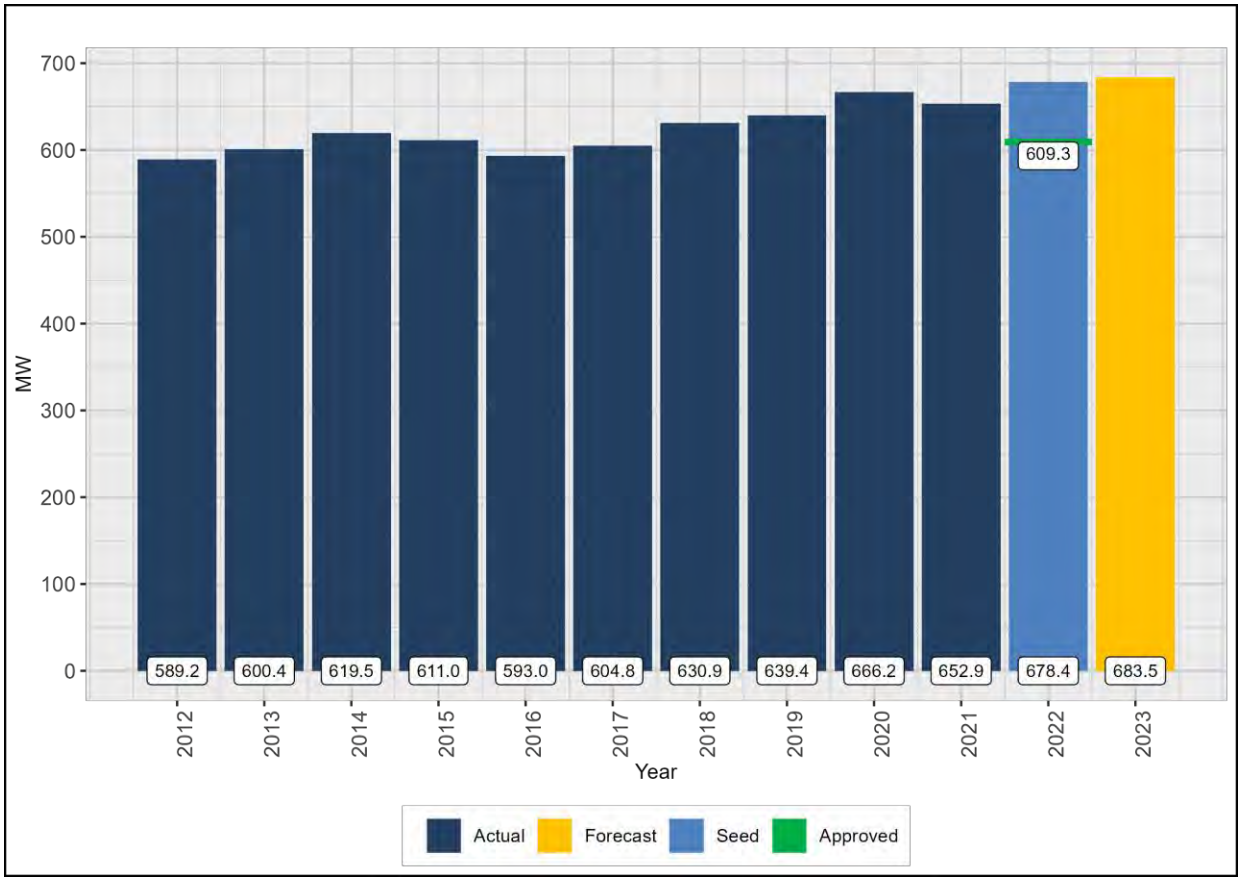


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a three-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2021 levels.

Overall, for 2023F, FBC is forecasting customer growth of 2.1 percent compared to 2022S and growth of 2.4 percent compared to 2022 Approved.

Table 3-3: Year-End Direct Customer Count

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
1	Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
2	Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
3	Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	39	47	49	50	50	50	52	51	43	42	42	42
5	Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
6	Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
7	**Total**	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.6 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2022 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)[10]

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Residential	$ 195.058	$ 200.837	$ 197.962
2	Commercial	104.380	107.153	106.230
3	Wholesale	51.255	53.722	52.031
4	Industrial	40.804	46.764	47.856
5	Lighting	2.411	2.266	2.207
6	Irrigation	3.386	3.550	3.554
7	Total	$ 397.294	$ 414.292	$ 409.840

When comparing the 2022 Approved to 2022 Projected there is an increase in revenue of $16.998 million, the majority of which is due to increased residential and industrial loads.

The 2023 Forecast revenue is $12.546 million higher than 2022 Approved, primarily due to an increase in the industrial load, followed by small increases in the residential, commercial, and wholesale loads. These increases are slightly offset by a decrease in the lighting load resulting from the continued conversion to LED streetlights in the FBC service territory.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 SUMMARY

The normalized after-savings gross load forecast for 2023F is 3,775 GWh. Based on net load of 3,476 GWh at the approved 2022 rates, FBC's 2023 revenue forecast is $409.840 million. When comparing 2023F to 2022 Approved, there is an increase in net load of 170 GWh. The net load increase in 2023F is due to increased loads in the industrial, commercial, wholesale residential and irrigation classes.

[10] The commercial sales revenue includes the revenues under RS 96 EV DCFC Stations. Please refer to Section 5.8 for further detail on EV DCFC station costs and revenues.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2022 Projected and 2023 Forecast power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the power supply cost.

As shown in Table 4-1 below, the 2023 Forecast power supply cost of $182.105 million represents an increase of 12.5 percent or $20.275 million compared to the 2022 Approved cost of $161.830 million. The increase in 2023 Forecast power supply cost is mainly due to increases in PPE, however, wheeling expense has increased as well. The 2023 Forecast PPE has increased as a result of increased gross load and a reduction in wholesale market purchases, which has resulted in a correspondingly greater reliance on energy supplied under BC Hydro Rate Schedule (RS) 3808. 2023 Forecast wheeling expense has increased as a result of both rates and usage. The 2023 Forecast water fee expense has decreased compared to 2022 Approved as a result of decreased usage.

Any variances between forecast and actual power supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Power Purchase Expense	$ 143.779	$ 153.164	$ 163.575
2	Wheeling Expense	6.093	6.330	6.987
3	Water Fees	11.958	11.916	11.543
4	Total Power Supply Cost	$ 161.830	$ 171.409	$ 182.105
5				
6	Gross Load (GWh)	3,591	3,786	3,775

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply, and market purchases to meet its load requirements. The Company's firm resources consist of:

1. Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year-to-year timing differences in the entitlement energy storage under the CPA;
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade

power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);
4. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
5. A number of small Independent Power Producer (IPP) contracts; and
6. A number of market purchase arrangements.

4.3 *PORTFOLIO OPTIMIZATION*

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply all of its 2023 forecast annual energy requirements, and most of its forecast capacity requirements with the exception of a small number of hours during June and July. These forecast capacity gaps result from the Company's updated, increased load forecast. As mentioned in previous Annual Reviews, the nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. However, in contrast to recent years, the regional electricity market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace PPA purchases on a forward basis. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 *FBC 2022/23 ANNUAL ELECTRIC CONTRACTING PLAN*

On May 2, 2022, FBC filed its 2022/23 Annual Electric Contracting Plan (AECP) with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and

annual energy requirements for the operating year commencing October 1, 2022 and ending September 30, 2023, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy, but could be more or less, depending on system conditions.[11] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecasts of PPE for the remainder of 2022 and for 2023 are based on the plan detailed in the 2022/23 AECP, which was accepted by the BCUC on May 26, 2022, by Letter L-19-22.[12]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2022/23 contract year equal to 767 GWh, less any firm market contracts that FBC could enter into, as described in Section 5 of the 2022/23 AECP. Prior to the June 30, 2022 nomination deadline, FBC updated its forecast load and resource balance for the 2022/23 contract year and submitted a nomination of 774 GWh.

4.5 *2022 PROJECTED POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2022 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 195 GWh above the 2022 Approved value, and PPE is projected to be above the 2022 Approved value by $9.385 million. The increase in 2022 Projected PPE is primarily due to the increase in gross load above the 2022 Approved value. This increase in gross load drives increases in both the BC Hydro PPA and wholesale market expense to meet the additional load. In addition, increases in both the purchase price under the BC Hydro PPA and the average cost of purchases from the market further contributed to the increase in PPE.

[11] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[12] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-19-22.

Table 4-2: 2022 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Difference
1	Brilliant	$ 41.841	$ 42.367	$ 0.526
2	BC Hydro PPA	44.062	49.539	5.477
3	Waneta Expansion	42.701	41.434	(1.267)
4	Market and Contracted Purchases	15.102	21.672	6.570
5	Independent Power Producers	0.073	0.058	(0.015)
6	Self-Generators	-	-	-
7	CPA Balancing Pool	-	(1.252)	(1.252)
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	-	(0.654)	(0.654)
10	Total	$ 143.779	$ 153.164	$ 9.385
11				
12	Gross Load (GWh)	3,591	3,786	195

4.6 *2023 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2023 Forecast PPE is $10.412 million greater than the 2022 Projected. The forecast increase from $153.164 million in 2022 to $163.575 million in 2023 is mainly a result of a reduction in market and contracted purchases as they increase in price and correspondingly, a greater reliance on energy supplied by BC Hydro as it becomes more cost effective compared to market. Furthermore, as a result of load growth and uneconomic wholesale market prices, FBC expects to take Tranche 1 PPA energy over the nominated amount during 2023. Tranche 1 PPA energy taken over the nominated amount costs 150 percent of the Tranche 1 embedded cost rate,[13] and this exposure to more expensive PPA energy is also contributing to increased costs. Also contributing to the increase are escalations to the Waneta Expansion and Brilliant contract rates.

Table 4-3 below shows a comparison of the 2022 Projected and 2023 Forecast PPE. Reasons for significant variances from the 2022 Projected PPE are discussed below.

[13] $50.94 per MWh x 150 percent = $76.41 per MWh.

Table 4-3: 2023 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2022	Forecast 2023	Difference
		-		
1	Brilliant	$ 42.367	$ 44.050	$ 1.683
2	BC Hydro PPA	49.539	71.302	21.763
3	Waneta Expansion	41.434	41.834	0.400
4	Market and Contracted Purchases	21.672	6.326	(15.346)
5	Independent Power Producers	0.058	0.062	0.004
6	Self-Generators	-	-	-
7	CPA Balancing Pool	(1.252)	-	1.252
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	(0.654)	-	0.654
10	Total	$ 153.164	$ 163.575	$ 10.412
11				
12	Gross Load (GWh)	3,786	3,775	(11)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2023 by $1.683 million compared to 2022 Projected due to increased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true-up to the prior year's actual costs compared to forecast.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2023 by $21.763 million compared to the 2022 Projected expense. The drivers of the increase are a higher purchased volume (371 GWh), which increases the expense by $21.775 million, and an increase in BC Hydro rates, which accounts for an increase of $3.987 million, for a total of $25.763 million. FBC has decreased its 2023 Forecast of PPA expense by $7.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2022 Projected BC Hydro expense was reduced by $3.000 million to account for potential real-time opportunities during the remainder of 2022. This results in a variance between 2022 Projected and 2023 Forecast of $21.763 million[14], as shown in Table 4-3. Actual market savings for the remainder of 2022 and 2023 may be higher or lower and will depend on system and market conditions at the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

4.6.3 Waneta Expansion

The $0.400 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, offset by a $0.291 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of

[14] $21.763 million is calculated as follows: Total increase of $25.763 million less the $4.000 million variance between the 2022 Projected and 2023 Forecast real-time opportunities, or, $25.763 million – ($7.000 million - $3.000 million).

capacity FBC releases to Powerex and the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from forward contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data, and technology company. The method used to forecast market prices and surplus sales is the same as in the Annual Review for 2022 Rates. The forecast of surplus capacity sales revenue in 2023, which is included in line 3 of Table 4-3, is approximately $10.700 million.

4.6.4 Market and Contracted Purchases

The $15.346 million decrease in Market and Contracted Purchases forecast for 2023 is due to a lesser volume purchased at higher rates when compared to 2022 Projected. Market and Contracted Purchases for 2022 Projected include both fixed price contracted purchases and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2023 Forecast are based on fixed price contracts executed by the Company, with the exception of forecast real-time market purchases for Rate Schedule 37[15] load. As discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2022 Projected PPE, FBC has stored a net total of 25 GWh of entitlement energy, valued at $1.252 million. For the 2023 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 *TRANSMISSION SERVICE LOSS RECOVERIES*

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load forecast (included in Tables 4-2 and 4-3, line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2022 and 2023 loss recoveries.

[15] RS 37 is large commercial stand-by service, which is on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2023 is 15 GWh or 0.4 percent of total gross load.

Table 4-4: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (OATT) as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2022 Rates. Table 4-5 below shows FBC's Wheeling Expense for 2022 and 2023.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,475	2,475	2,670
3	Creston	420	420	420
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.903	$ 4.976	$ 5.555
7	Creston	0.542	0.550	0.570
8	Other	0.648	0.804	0.863
9	Total Wheeling Expense	$ 6.093	$ 6.330	$ 6.987

Total 2022 Projected wheeling expense is $0.237 million greater than 2022 Approved. The 2022 Projected ARWA costs are $5.526 million (lines 6 and 7 in the table above), a $0.081 million increase when compared to 2022 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2022 Projected Teck and OATT wheeling costs are $0.804 million (line 8 above), which is $0.156 greater than 2022 Approved. This is mainly due to increased use of OATT wheeling.

2023 Forecast wheeling expense is $0.657 million higher than 2022 Projected. This is a result of both increased use and rates. FBC increased the Okanagan wheeling nomination to 2,670 MW months in 2023 from 2,475 MW months in 2022. ARWA rates are forecast to increase on October 1 of both 2022 and 2023, based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2023 Forecast water fees are decreasing by $0.373 million from the 2022 Projected due to decreased entitlement use. 2023 water fees are forecast using the same method as in the Annual Review for 2022 Rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Plant Entitlement in Previous Year (GWh)	1,679	1,663	1,571
2				
3	Water Fees	$ 11.958	$ 11.916	$ 11.543

4.10 SUMMARY

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing and is consistent with the 2022/23 AECP. Any variances in the power supply cost, including any decreases in PPE due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.[16]

FBC is forecasting Other Revenue for 2023 to be $0.409 million higher than 2022 Approved, primarily due to higher Late Payment Charges and expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

2022 Projected Other Revenue is $1.335 million higher than 2022 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue and Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Apparatus and Facilities Rental	$ 6.018	$ 6.018	$ 6.108
2	Contract Revenue	2.277	2.750	2.367
3	Transmission Access Revenue	1.771	1.788	1.834
4	Interest Income	0.020	0.020	0.030
5	Late Payment Charges	0.875	1.095	0.994
6	Connection Charges	0.505	0.505	0.553
7	EV Stations Carbon Credits	-	0.625	-
8	Other Recoveries	0.366	0.366	0.355
9	Total Other Revenue	$ 11.832	$ 13.167	$ 12.241

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. There are no variances projected in 2022 compared to 2022 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2023 Forecast is higher than 2022 Approved due to expected escalations in unit rental rates for continuing contracts.

[16] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

5.3 CONTRACT REVENUE

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third-party work, and the associated management fees earned, fluctuates from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third-party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[17] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2022 Projected revenue is higher than 2022 Approved due to an increase in costs related to the close-out of a multi-year asset refurbishment project for a third party that began in 2020, as well as certain costs that shifted from 2021 into 2022 for the same project. The 2023 Forecast is higher than 2022 Approved due to expected increases in the average cost of work and materials recovered from third-party customers.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2022 Projected revenue is slightly higher than 2022 Approved due to a higher nomination than originally forecast for one customer. The 2023 Forecast is higher than 2022 Approved due to the phased increase in rates over three years beginning January 1, 2020, as approved by Order G-40-19.

5.5 INTEREST INCOME

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans outstanding; as a result, no significant changes in interest income are expected in 2022 Projected or the 2023 Forecast.

5.6 LATE PAYMENT CHARGES

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to the impact of the COVID-19 pandemic and FBC's implementation of customer relief measures, which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated from year to year.

[17] As approved by Order G-5-10A.

FBC continues to see fluctuations in Late Payment Charges. The 2022 Projected Late Payment Charges are higher than 2022 Approved by $0.220 million based on amounts charged so far in 2022 as well as growth in customers since the 2017 to 2019 period used to develop the 2022 Approved.

In consideration of the continued fluctuations being experienced, the 2023 Forecast has been calculated based on the average of 2021 Actual and 2022 Projected Late Payment Charges of $0.892 million and $1.095 million, respectively. This results in an increase in Late Payment Charges of $0.119 million compared to 2022 Approved.

5.7 *CONNECTION CHARGES*

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2022 Projected is expected to be consistent with 2022 Approved based on amounts charged so far in 2022. The 2023 Forecast is expected to be higher than 2022 Approved based on customer growth and forecast customer reconnections.

5.8 *CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS*

FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[18] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. The EV charging rates, the depreciation rate for EV charging stations, and the inclusion of related revenues and expenses associated with FBC's EV DCFC stations in FBC's regulated accounts were approved by the BCUC on November 24, 2021[19]. The revenues to be included in FBC's regulated accounts include the Other Revenue from the sale of carbon credits related to EV stations[20] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR), which is embedded in the rate design of the EV DCFC stations.

At the time of the 2022 Annual Review, FBC did not have any carbon credits validated by the British Columbia Low Carbon Fuel Standard (BC-LCFS); as such, and as reflected in Table 5-1 above, FBC did not forecast any revenue from the sales of the credits for 2022 Approved. However, as of the end of the first quarter of 2022, the BC-LCFS has validated approximately 1,337 carbon credits for FBC that have accumulated since 2019, with an approximate market value of $0.625 million[21]. FBC anticipates monetizing these credits prior to the end of 2022 and has therefore reflected them in the 2022 Projected column in Table 5-1 above, and also included the $0.625 million credit in the Flow-through deferral account, to be returned to customers in 2023.

[18] Order G-215-21 dated July 14, 2021.

[19] FBC EV DCFC Service Application Decision and Order G-341-21.

[20] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's 2022 Annual Review, BCSEA IR1 4.3. Beginning in 2022, FBC will only be permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.

[21] 1,337 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023.

As part of the 2022 Annual Review Decision, FBC was directed to include the following in future Annual Review filings:[22]

> …an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.

FBC currently has a total of 40 EV DCFC stations in service across 23 sites and is planning to install two additional DCFC stations at two of the existing sites in 2022, resulting in a total of 42 EV DCFC stations across 23 sites. Consistent with the format of the information provided during the 2022 Annual Review[23], Table 5-2 below provides the costs and revenues for 2021 Actual (previous fiscal year), 2022 Projected, and 2023 Forecast. As highlighted in Table 3-4 of Section 3.6, the RS 96 EV DCFC revenue (i.e., Line 10 of Table 5-2 below) is included as part of the Commercial Sales Revenue. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses for the EV DCFC stations and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations, as well as information on how the two new stations are prescribed undertakings. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 5-2 below.

Table 5-2: EV DCFC Stations Costs and Revenues for 2021 Actual, 2022 Projected, and 2023 Forecast ($ millions)[24]

Line	Particulars	2021 Actual	2022 Projected	2023 Forecast	Cumulative
1	Cost of Energy	0.013	0.282	0.300	
2	Less: Power Purchase Expense	(0.013)	-	-	
3	O&M	0.101	0.187	0.193	
4	Depreciation	0.307	0.456	0.612	
5	Amortization of CIAC	(0.150)	(0.191)	(0.249)	
6	Other Revenue - Carbon Credits	-	(0.625)	-	
7	Income Tax	(0.299)	(0.199)	0.158	
8	Earned Return	0.124	0.172	0.183	
9	Total Cost of Service	0.083	0.082	1.196	
10	RS 96 Revenue	(0.058)	(0.155)	(0.178)	
11	(Surplus) / Deficiency	0.025	(0.072)	1.018	0.971
12	Prior Year 2018-2020 (Surplus)/Deficiency				(0.142)
13	Cumulative (Surplus) / Deficiency				0.828

[22] FBC 2022 Annual Review Decision and Order G-374-21, p. 32.
[23] Exhibit B-3, BCUC IR1 16.1.
[24] As explained in Exhibit B-3, BCUC IR1 16.1 of the FBC 2022 Annual Review, RS 96 was approved on an interim basis in 2021 by Order G-9-18 in which the cost of energy embedded was based on BC Hydro's RS 3808; therefore,

As directed by Order G-341-21, FBC is to file a detailed assessment of the EV DCFC service by no later than December 31, 2022 or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. FBC is not expecting to receive approval from Measurement Canada prior to December 31, 2022; thus, FBC will file the detailed assessment report by December 31, 2022. As directed by the BCUC, the detailed assessment will include:

- An update of the financial models with actual and forecast information and updated assumptions;
- A detailed assessment of RS 96 and alternative rate design options;
- An overview of the current EV fast charging service market and rates across Canada and the United States;
- A proposal for a depreciation rate for its EV DCFC stations and information to support its proposal; and
- An assessment as to whether idling fees are warranted.

5.9 *OTHER RECOVERIES*

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and AMI radio-off meter read fees. There are no variances expected in 2022 Projected compared to 2022 Approved based on amounts recognized to date. The 2023 Forecast is expected to be slightly lower than 2022 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 *SUMMARY*

FBC has forecast the Other Revenue components for 2023 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

the cost of energy for 2021 Actual shown in Table 5-2 is equal to the power purchase expense. As approved in Order G-341-21, the permanent rate for RS 96 is based on FBC's commercial service RS 21. As such, starting in 2022, the cost of energy shown in Table 5-2 above is based on FBC's commercial service RS 21.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In 2023, the formula O&M is $69.957 million, representing a 5.8 percent increase from the 2022 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $2.323 million, representing a 26.8 percent increase from the amount approved for 2022. Overall, the 2023 Forecast gross O&M expense is $72.789 million, which is an increase of approximately 7.0 percent from the 2022 Approved level.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 66.147	$ 66.147	$ 69.957	Section 11, Schedule 20, Line 8
2	Forecast O&M	1.832	1.635	2.323	Section 11, Schedule 20, Line 20
3	Prior year O&M True-up	0.053	0.053	0.509	Table 6-2, line 16
4	Total Gross O&M	68.032	67.835	72.789	Line 1 through 3
5	Capitalized Overhead	(10.177)	(10.177)	(10.918)	Section 11, Schedule 20, Line 23
6	Net O&M	$ 57.855	$ 57.658	$ 61.871	Line 4 + Line 5

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision,[25] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.017 percent.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

[25] MRP Decision, p. 118.

2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	455	G-374-21 FBC 2022 Annual Review
2	I-Factor		4.017%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	473	
4	Average Customer Forecast		147,901	Section 2, Table 2-3, Line 13
5	2023 Inflation-Indexed O&M before 2020 True-up	$	69.957	Line 3 x Line 4 / 1,000,000
6	2021 True-up O&M		0.509	Line 16
7	Inflation-Indexed O&M	$	70.466	Line 5 + Line 6
8				
9	2021 O&M True-up			
10	2021 Actual 12 month Average Customers		144,877	FBC 2021 Annual Report
11	2021 Forecast 12 month Average Customers		143,325	G-42-21 FBC 2020-2021 Annual Review
12	Difference		1,552	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		1,164	Line 12 x Line 13
15	2021 Unit Costs	$	437	G-42-21 FBC 2020-2021 Annual Review
16	O&M True-up for 2023	$	0.509	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.080	$ 0.278	$ 0.199	$ 0.436
2	Generation Dam Safety	$ 0.246	$ 0.415	$ 0.169	$ 0.137
3	Network Operations Apprentice Program	$ 0.209	$ 0.243	$ 0.034	$ (0.167)
4	Cyber Security	$ 0.085	$ 0.085	$ -	$ 0.250
5	Data Analytics	$ 0.105	$ -	$ (0.105)	$ (0.206)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.724	$ 1.021	$ 0.297	$ 0.449

Notes to Table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.668%).
[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $1.021 million, which is $0.297 million higher than the 2021 Formula O&M amount. Areas with notable variances include tree management, generation dam safety and data analytics.

For tree management, FBC spent $0.199 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.169 million more than the formula amount due to the continuation of dam safety review activities from 2020, as FBC required more time to complete the analysis for the determination of the dam classifications for the Upper Bonnington, Lower Bonnington and South Slocan plants.

Offsetting the higher costs in these two categories was lower spending in data analytics. FBC spent $0.105 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FBC focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For the first two years of the MRP, FBC spent $0.449 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

In addition to FBC's formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost

of service associated with Clean Growth initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review.

The 2023 amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ (1.716)	$ (1.716)	$ (1.297)
2	Insurance Premiums	2.223	2.291	2.457
3	BCUC Levies	0.373	0.373	0.385
4	Clean Growth Initiative - EV DCFC Stations	0.187	0.187	0.193
5	Exogenous Factor - MRS	0.765	0.500	0.585
6	Total Forecast O&M	$ 1.832	$ 1.635	$ 2.323

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ (1.716)	$ (1.716)	$ (1.297)
2	Capital (Approved)	3.807	3.807	1.888
3	Capital (to Pension & OPEB Variance Deferral)[1]	(0.400)	(0.400)	-
4	Total	$ 1.691	$ 1.691	$ 0.591

Notes to Table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Capital Expenditure forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates

updated for 2023 rate-setting purposes. There is no difference for 2023 since FBC was directed to file an updated forecast of the 2023 and 2024 Regular Capital Expenditures in the 2023 Annual Review, as directed in the MRP Decision and Order G-166-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 3 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2023 Forecast pension and OPEB expense has decreased by $1.100 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $3 million decrease in current service costs due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense;

offset in part by:

- An approximate $2 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 2.223	$ 2.291	$ 2.457	Section 11, Schedule 20, Line 16
2	Total	$ 2.223	$ 2.291	$ 2.457	

The 2022 Projected insurance premium expense of $2.291 million is $0.068 million higher than 2022 Approved, as it incorporates FBC's actual July 2022 to June 2023 insurance renewals of $2.253 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $2.457 million, which is an increase of $0.166 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $1.126 million and

applying a 5 percent increase for the remaining six months, plus the cost of fire fighting services FBC pays to the Province of $0.148 million.[26]

6.3.3 BCUC Levies

FBC's 2023 Forecast for BCUC levies is $0.385 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[27] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 5-2 in Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

As shown in Table 6-7 below, the 2022 Projected EV DCFC station O&M expense is expected to be consistent with 2022 Approved[28], and consists of network management, repairs and maintenance, inspection fees and FBC labour costs. The 2023 Forecast EV DCFC station O&M expense is anticipated to be similar to the 2022 Projected level, with an approximate increase of $6 thousand primarily due to inflation.

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ 0.187	$ 0.187	$ 0.193	Section 11, Schedule 20, Line 19
2	Total	$ 0.187	$ 0.187	$ 0.193	

6.3.5 MRS Incremental Operating Expenses

In the 2022 Annual Review Decision,[29] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the 2022

[26] $2.253 million/2 = $1.126 million. $1.126 million x 1.05 = $1.183 million. $1.126 million + $1.183 million + $0.148 million annual firefighting service fee = $2.457 million.

[27] Order G-215-21 dated July 14, 2021.

[28] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 6-7 is the amount included in the Compliance Filing.

[29] Decision and Order G-374-21, p. 21.

Annual Review, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[30].

BC Hydro issued AR13 on May 1, 2020 recommending adoption of seven standards, retirement of one standard, and holding one standard in abeyance pending resolution of the Planning Coordinator (PC) function along with the NERC Glossary dated August 12, 2019. The BCUC issued Order R-19-20 on September 8, 2020 accepting BC Hydro's recommendation and determined the effective dates of those standards. Of the standards and respective NERC Glossary terms assessed by FBC, five standards have associated costs, of which one was held in abeyance. The effective date for the four adopted standards is April 1, 2023, including the existing CIP-005-6 (Electronic Security Perimeter(s)), CIP-008-6 (Incident Reporting and Response Planning) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments) standards and the new CIP-013-1 (Supply Chain Risk Management) standard. In order to address these changes, FBC is required to monitor and disconnect vendor remote access, evaluate and report attempts to compromise, ensure software downloads and installations are unaltered and secure, and assess risk for any product or service procured for Bulk Electrical System assets under the Critical Infrastructure and Protection (CIP) standards. These requirements are reflected in the 2022 Approved, 2022 Projected, and 2023 Forecast expenses in Table 6-8 below.

The following table provides the 2022 Approved and Projected and the 2023 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.335	$ 0.200	$ 0.490	
2	Non-Labour	0.280	0.250	0.095	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.765	$ 0.500	$ 0.585	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is lower than 2022 Approved by $0.265 million. The reduction of $0.265 million is a result of less overall effort required to modify existing programs and processes as mentioned above than originally expected.

The 2023 Forecast O&M expense of $0.585 million is related to the expected ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. The 2023 Forecast is based on the expected costs in 2022 Projected and is therefore less than the 2022 Approved level. These costs are annual and will continue in future years.

[30] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.4 NET O&M EXPENSE

Net O&M expense is gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2022. After capitalized overhead, the net O&M expense is $61.871 million in 2023.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 7.0 percent. Formula-driven O&M is increasing at a rate of 5.8 percent, and O&M forecast outside the formula is 26.8 percent higher than 2022 Approved.

The capitalized overhead rate for 2023 remains unchanged from 2022.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.675 billion for 2023. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[31]

FBC's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $94.209 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $64.407 million; and
- Capital additions of CPCNs and other Major Projects totalling $45.439 million[32], as discussed in Section 7.3 below, which include:
  - Full-year impact of $21.250 million for the capital expenditures and related AFUDC for the Kelowna Bulk Transformer Additions (KBTA) Project, which is expected to complete in late 2022 or early 2023;
  - Full-year impact of $16.151 million for the final capital expenditures and related AFUDC for the Corra Linn Dam Spillway Gates Replacement Project, which is expected to complete in 2022; and
  - Full-year impact of $8.036 million for the final capital expenditures and related AFUDC for the Playmor Substation Upgrade Project, which is expected to complete in 2022.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $24.303 million in 2023.

Details of the 2023 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures for the years 2020 through 2022; and

[31] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.
[32] The 2023 capital additions of $45.439 million also include $0.002 million for the close out costs and related AFUDC in 2022 for the UBO Old Units Refurbishment Project.

- Approval of a number of items to be forecast on an annual basis.

Further, in the MRP Decision the BCUC directed FBC to file an updated forecast of the 2023 and 2024 regular capital expenditures in the 2023 Annual Review.[33]

The components of FBC's 2023 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Forecast Capital	$ 81.925	$ 87.735	$ 94.428	Table 7-2 and Table 7-3, Line 4
2	Flow-Through Capital	0.935	2.430	0.248	Table 7-11, Line 3
3	Total Gross Regular Capital	$ 82.860	$ 90.165	$ 94.676	Sum of Lines 1 & 2
4	Less CIAC	(11.712)	(8.287)	(11.628)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 71.148	$ 81.878	$ 83.048	Sum of Lines 3 & 4

In Section 7.2.1, FBC provides its updated 2023 and 2024 regular capital forecasts. In Section 7.2.2, FBC provides details on its forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Updated 2023 and 2024 Forecast Regular Capital Expenditures

As stated above, in the MRP Decision and Order G-166-20[34], the BCUC directed FBC to file updated 2023 and 2024 regular capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FBC's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FBC to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[35]

As further explained below, FBC has begun to experience pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including supply chain issues and rising commodity prices and other inflationary pressures brought on by the COVID-19 pandemic and the war in Ukraine. These factors, as well as the increased cost and complexity in permitting and land acquisition as well as increased growth, are impacting FBC's ability to execute on all of its planned capital projects and programs. While FBC has pursued various mitigation measures to manage through the spending

[33] MRP Decision and Order G-166-20, p. 131.
[34] Directive 1.c. of Order G-166-20.
[35] MRP Decision and Order G-165-20, p. 131.

pressures, FBC requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the growth, sustainment and other capital expenditures[36]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FBC's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Regular Capital Expenditures, 2020-2022 Approved and 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Growth Capital	27.029	23.042	24.339	26.283	23.170
2	Sustainment Capital	50.463	49.818	42.830	44.377	53.470
3	Other Capital	15.752	14.712	14.756	15.281	15.134
4	Total	93.244	87.573	81.925	85.941	91.774

Table 7-3: Regular Capital Expenditures, 2020-2021 Actual, 2022 Projected and 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Growth Capital	28.799	21.865	29.868	30.973	24.568
2	Sustainment Capital	47.325	49.601	41.486	45.797	58.673
3	Other Capital	16.036	15.349	16.381	17.658	17.213
4	Total	92.160	86.815	87.735	94.428	100.454

In Section 7.2.1.1, FBC describes its updated forecasts for growth and sustainment capital. In Section 7.2.1.2, FBC describes its updated forecasts for other capital.

7.2.1.1 Growth and Sustainment Capital

7.2.1.1.1 GROWTH CAPITAL

Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The three main growth capital portfolios are: (i) Transmission Growth; (ii) Distribution Growth; and (iii) New Connects. In the MRP Application, FBC provided forecasts of these three categories of

[36] Excluding sustainment CIAC.

growth capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Growth Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Transmission Growth	5.172	7.109	2.063	0.744	2.740	5.524
2	Distribution Growth	3.716	1.926	1.876	1.965	1.807	3.450
3	New Connects	18.141	19.764	19.104	19.156	19.792	20.894
4	Total Growth Capital	27.029	28.799	23.042	21.865	24.339	29.868

Table 7-5: Growth Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Transmission Growth	5.195	6.223	1.086	1.088
2	Distribution Growth	1.899	2.800	1.921	1.716
3	New Connects	19.188	21.951	20.163	21.764
4	Total Growth Capital	26.283	30.973	23.170	24.568

As shown in Table 7-5 above, FBC's Updated Forecasts for growth capital have increased by $4.690 million in 2023 and $1.398 million in 2024 compared to the Original Forecasts. FBC is forecasting increases in all three growth capital portfolios in 2023. For 2024, the increase is primarily in the New Connects portfolio, with FBC reducing the expenditures for the Distribution Growth portfolio to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.2 SUSTAINMENT CAPITAL

The expenditures within sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The five main sustainment capital portfolios are: (i) Generation; (ii) Transmission Sustainment; (iii) Stations Sustainment; (iv) Distribution Sustainment; and (v) Telecommunications. In the MRP

Application, FBC provided forecasts of these five categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-6: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Generation	6.697	5.884	6.766	6.949	6.309	6.731
2	Transmission Sustainment	8.353	12.506	6.387	10.667	5.698	7.841
3	Stations Sustainment	13.538	4.821	13.624	12.083	5.279	6.889
4	Distribution Sustainment	20.057	21.530	20.058	17.479	19.262	17.439
5	Telecommunications	1.818	2.584	2.983	2.423	6.280	2.587
6	Total Sustainment Capital	50.463	47.325	49.818	49.601	42.830	41.486

Table 7-7: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Generation	7.008	7.623	6.514	7.225
2	Transmission Sustainment	7.951	9.159	7.591	12.800
3	Stations Sustainment	3.793	7.928	15.971	15.229
4	Distribution Sustainment	19.710	17.480	19.922	18.219
5	Telecommunications	5.915	3.606	3.472	5.199
6	Total Sustainment Capital	44.377	45.797	53.470	58.673

As shown in Table 7-7 above, FBC's Updated Forecasts for sustainment capital have increased by $1.420 million in 2023 and $5.203 million in 2024 compared to the Original Forecasts. For 2023, the increases are primarily in the Transmission Sustainment and the Stations Sustainment portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Telecommunications portfolios to offset some of the required increases. For 2024, the increases are primarily in the Transmission Sustainment and Telecommunications portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Stations Sustainment portfolios to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.3 DRIVERS OF UPDATED GROWTH AND SUSTAINMENT CAPITAL FORECASTS

The drivers of the increases in growth and sustainment capital are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increases in growth capital as a result of more customer applications; and
- Additional reliability, refurbishment or end of life projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FBC has undertaken during the first three years of the MRP term, are described in the following subsections.

FBC is Experiencing Significant Inflationary Pressures

FBC's Original Forecasts were developed using an assumption of two percent for annual inflation. While FBC has generally managed its overall capital spending within the approved levels over the first two years of the MRP term, FBC has begun to experience pressures throughout its growth and sustainment portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had a significant impact on market conditions for many commodities and services that make up FBC's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FBC's experience, FBC engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 17.5 percent in capital costs for electric utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

FBC has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and 2024. In particular, FBC has experienced the most significant inflationary cost pressures for poles, transformers and wires/cables. The projects in Transmission, Distribution and Station growth and sustainment portfolios have been impacted by incremental increases in the cost of these materials since 2020. Cost escalation is also impacting FBC due to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

As shown in the Wood Mackenzie Report, it is expected that the average capital costs for electric utilities will continue to rise until the fourth quarter of 2024, although at a slower pace than what was experienced between the first quarter of 2020 and the first quarter of 2022, and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[37] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

[37] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

Updated Forecasts Reflect Increased Growth

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on a historical rolling average of expenditures adjusted by inflation. The overall increase is due to more customer applications for connections.

Updated Forecasts Reflect New Growth and Sustainment Projects

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FBC identified projects over $1 million that it anticipated undertaking over the five-year MRP term. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

For example, in order to address aging infrastructure and to support load growth while maintaining current levels of reliability, substation rebuild projects or transformer addition projects are required. In some cases, these projects require increasing the station footprint and acquiring more adjacent land or larger parcels of land in new locations. The selection of an appropriate land parcel can be a lengthy process that can include activities such as open houses as part of stakeholder consultation. Given the uncertainties related to consultation and purchase negotiation, it introduces risk to project timelines if these activities are not completed in advance of the project execution window. The need to acquire land has arisen in a number of FBC's planned projects and has resulted in increased costs and, at times, delays to the project schedule. Projects that have been impacted by land acquisition requirements are described in Appendix C2 and include, as an example, the Fruitvale Station Upgrade project.

As detailed in the MRP Application[38], FBC actively manages its capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall regular capital forecasts are subject to change, and FBC may identify new projects and programs that need to be added over the term of the MRP. The capital plan contains a mix of projects across the portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FBC has consistently executed a similar portfolio of work to the Original Forecasts.

[38] Section 3.4.1.5, page C-106.

In Appendix C2, FBC provides a list of the projects over $1 million which are included in the Updated Forecasts for 2023 and 2024.

FBC Employed Mitigation Strategies to Limit Cost Pressures

FBC has implemented the following strategies to mitigate the impact of the aforementioned cost pressures:

- Re-scheduling projects that can be safely re-scheduled to 2023 to accommodate other project costs increase that could not be deferred. As detailed in Section 3.2 (Capital Planning Process – page C-52) of the MRP Application, FBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change, and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that is expected to occur throughout the year within the resource and budget constraints of the capital plan. While FBC has delayed some work with flexible timing to accommodate the increased demands in 2022, this has only mitigated part of the capital pressures due to the magnitude of market pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large contracts for materials and services to ensure competitive pricing;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreement with unionized FBC employees that provide longer-term stability for internal labour rates (IBEW and MoveUP agreement expires in 2023); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, FBC has not been able to fully mitigate cost increases due to the cost drivers described above.

7.2.1.2 Other Capital

In this section, FBC provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities and Information System (IS) expenditures.

Table 7-8 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-9 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FBC notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-8: Approved and Actual/Projected Other Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	3.407	3.444	3.338	2.711	3.274	3.560
2	Facilities	3.264	3.434	2.346	3.685	2.346	2.846
3	Information Systems	9.081	9.158	9.028	8.953	9.136	9.975
4	Total Other Capital	15.752	16.036	14.712	15.349	14.756	16.381

Table 7-9: Original and Updated Forecasts of Other Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	3.681	4.099	3.388	3.717
2	Facilities	2.346	4.305	2.346	4.096
3	Information Systems	9.254	9.254	9.400	9.400
4	Total Other Capital	15.281	17.658	15.134	17.213

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

FBC's 2023 and 2024 capital forecasts for Equipment have increased by $0.418 million and $0.329 million, respectively, compared to the Original Forecasts. The average unit cost per vehicle has risen significantly as supply of vehicles has reduced in relation to demand in the marketplace. In particular, FBC is experiencing the following changes to the average cost of the vehicles:

- Substantial reduction in volume-based concessions from manufacturers to all commercial fleet (from $10.5 thousand to $2.5 thousand per unit);
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on transport of materials, services and labour by manufacturers;

7.2.1.2.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

As shown in Table 7-9 above, FBC's 2023 and 2024 Facilities capital forecasts have increased by $1.959 million and $1.750 million in 2023 and 2024, respectively, compared to the Original

Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FBC is planning to undertake to improve the adaptability and resiliency of FBC's facilities; and (ii) the installation of EV infrastructure at FBC's facilities.

Kelowna Space Project

FBC continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FBC's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FBC was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.930 million. Of this total, approximately $2.934 million is allocated to FBC based on employee count, with $1.209 million and $1.000 million reflected in FBC's Updated Forecasts for 2023 and 2024, respectively[39].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[39] There was also approximately $0.631 million and $0.094 million of actual costs related to the Kelowna Space Project allocated to FBC in 2020 and 2021, respectively, with the total allocation to FBC equaling approximately $2.934 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution ensures Electric Operations remain located in an area that best supports their service territory; by not relocating this group farther from the city, potential inefficiencies are prevented;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $0.750 million in each year for expenditures that are specifically in support of energy efficiency and GHG emissions reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FBC's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FBC to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FBC's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FBC is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FBC also plans to install EV charging infrastructure at FBC's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS

FBC's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-8 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with what was forecast in the MRP Application. As such, FBC has not made any changes to the 2023 and 2024 IS capital forecasts (Table 7-9 above) compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that would warrant revisions.

7.2.1.3 Summary of FBC's Updated Regular Capital for 2023 and 2024

FBC provided an updated forecast for regular growth, sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-10 below.

Table 7-10: Summary of 2023-2024 Updated Forecasts of Regular Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Growth Capital	30.973	24.568
2	Sustainment Capital	45.797	58.673
3	Other Capital	17.658	17.213
4	Total Regular Capital	94.428	100.454

For FBC's growth and sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FBC's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine, as well as growth-related expenditures and necessary reliability, refurbishment and end of life replacement projects. The Updated Forecasts will ensure FBC's ability to execute its planned growth and sustainment capital programs which are critical to ensuring the ongoing safe and reliable operation of FBC's system and ensuring that FBC is able to meet its customer's needs.

For FBC's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FBC's facilities related to energy efficiency and GHG emissions reductions.

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to Clean Growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2023 are shown in Table 7-11 below along with a comparison to 2022.

Table 7-11: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ -	$ 1.560	$ 0.248	
2	Exogenous Factor - MRS	0.935	0.870	-	
3	Forecast Capital Expenditures	$ 0.935	$ 2.430	$ 0.248	Section 11, Schedule 4, Line 10

7.2.2.1 EV DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[40], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 5-2 of Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

Table 7-11 above shows the EV DCFC stations capital expenditures for 2022 Approved[41], 2022 Projected, and 2023 Forecast. FBC originally did not forecast any EV DCFC station capital in 2022 during the 2022 Annual Review as FBC expected all construction activities to be completed in 2021. However, the originally planned construction activities in 2021 were delayed to 2022 mainly due to the flooding experienced in the latter part of 2021 which also led to FBC being required to undergo design changes to 16 of its DCFC sites to complete a required safety retrofit for the power supply kiosks. The flooding caused delays in construction and deployment for two planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21[42]. This resulted in an increase in capital expenditures for 2022 Projected when compared to 2022 Approved. FBC notes the reduction in expenditures for 2021 due to the delayed deployment of the Keremeos and Princeton stations was offset by the installation of two new DCFC stations in late 2021 at existing sites (i.e., Naramata and Grand Forks). Installations at Keremeos and Princeton are planned to be completed by the end of 2022, which by then will bring the total number of DCFC stations in service to 42 across the 23 sites. At this time, FBC is not expecting to construct any additional

[40] Order G-215-21 dated July 14, 2021.
[41] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 7-11 is the amount included in the Compliance Filing.
[42] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand. For 2023, FBC is forecasting to complete accessibility improvements for its existing EV DCFC sites. These improvements include new or additional lighting as the stations are available for use 24 hours a day, and paving for wheelchairs access to the charger.

The two new DCFC stations were installed at the existing Naramata and Grand Forks sites that only have a single DCFC station installed previously. Both Naramata and Grand Forks were identified in FBC's Revised Application for EV DCFC Service, and construction of these two additional stations was completed in late 2021. As directed by Order G-341-21[43], FBC is to include evaluation of any additional EV charging stations that were not originally identified in the Revised EV DCFC Service Application in FBC's Annual Review process, including review of whether the additional stations meet the criteria to be a prescribed undertaking under the GGRR and assessment of whether the levelized rate under RS 96 EV DCFC service will need to be recalculated as a result of the additional EV charging stations. Consistent with the information provided in FBC's Revised EV DCFC Application, Table 7-12 below shows that these two additional stations are prescribed undertakings and meet the requirements as set out in section 5 of the GGRR. Regarding the review of the levelized rate under RS 96 EV DCFC service, as discussed in Section 5.8, FBC is required to file a detailed assessment of the EV DCFC service by the end of December 31, 2022, which includes an update of the financial models with actual and forecast information as well as a detailed assessment of RS 96 and alternative rate design options. For the purposes of regulatory efficiency, FBC will address the review of the levelized rate under RS 96 EV DCFC service in the assessment report.

Table 7-12: Assessment of New EV DCFC Stations as Prescribed Undertakings Under the GGRR

	Greenhouse Gas Reduction Regulation Criteria						
GGRR Section	5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(c)
	Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that		For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
					The station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality? (Population – 2021 Census)	
Sites							
Naramata	Yes	Yes	Yes	Yes	Q4 2021	No[1]	Yes
Grand Forks	Yes	Yes	Yes	Yes	Q4 2021	No (4,112)	Yes

[43] Decision and Order G-341-21, p. 27.

Note to Table:

[1] Not located in a municipality as defined by the Community Charter.

7.2.2.2 Mandatory Reliability Standards Incremental Capital

As explained in Section 6.3.5, the incremental capital expenditures related to the adoption of MRS AR13 were approved for exogenous factor treatment in the 2022 Annual Review Decision. These costs are for the implementation of changes/additions, including the development and implementation of methods to monitor network traffic and software tools to support the changes/additions to the standards. The implementation of the required changes/additions requires the purchase and installation of hardware and software to assess and evaluate network traffic and the development of software tools to track risk assessments of any product or service procured for Bulk Electrical System assets.

Table 7-13 below shows the incremental capital expenditures related to MRS AR13 with a breakdown between labour, non-labour and contingency for 2022 Approved, 2022 Projected and 2023 Forecast.

Table 7-13: Incremental Capital Expenditures for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.580	$ 0.680	$ -	
2	Non-Labour	0.205	0.140	-	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.935	$ 0.870	-	Section 11, Schedule 4, Line 8

As shown in the table above, the 2022 Projected capital expenditures are approximately $0.065 million less than 2022 Approved. The reason for the variance is that FBC was able to purchase some software early (i.e., at the end of 2021 instead of 2022). Overall, there is no change to the original total estimate of $0.935 million (i.e., $0.065 million in 2021 Actual and $0.870 million in 2022 Projected).

As explained in the 2022 Annual Review[44], FBC is not expecting any incremental capital costs for 2023; therefore, the 2023 Forecast is zero. As the capital expenditures related to MRS AR13 are approved for flow-through treatment, any variances from Projected and Forecast amounts for the adoption of MRS AR13 will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[45] the

[44] Exhibit B-3, BCUC IR1 24.2.
[45] MRP Decision and Order G-166-20, pp. 132-133.

BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

For 2023, FBC is forecasting capital expenditures related to the KBTA project only. However, FBC's 2023 Forecast rate base also includes the full-year impact of capital additions related to the Corra Linn Dam Spillway Gate Replacement project, the UBO Old Units Refurbishment project, and the Playmor Substation Upgrade project, all of which are expected to complete in 2022. Each of these approved projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The new transformer is scheduled to be in service by the end of 2022 or early 2023, with project close-out in 2023, at an estimated cost of $23.288 million, inclusive of AFUDC and cost of removal. FBC forecasts capital expenditures of $11.384 million and $1.710 million (excluding AFUDC) in 2022 and 2023, respectively, with $21.250 million to be added to rate base on January 1, 2023 and the remainder added to rate base on January 1, 2024.

Corra Linn Dam Spillway Gate Replacement Project

The Corra Linn Dam Spillway Gate Replacement project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be complete in 2022 at a cost of $79.727 million, inclusive of AFUDC and cost of removal. Thus, FBC is not forecasting any capital expenditures related to this project in 2023. Since 2020, a total of $51.768 million has been added to FBC's rate base with the remaining $16.151 million forecast to be added to rate base in 2023. Overall, $67.919 million is forecast to be added to rate base by January 1, 2023 ($51.768 million of actual from 2020 to 2022 plus $16.151 million of 2023 Forecast), plus $11.808 million of cost of removal, for a total estimated project cost of $79.727 million including AFUDC and cost of removal.

UBO Old Units Refurbishment Project

The UBO Old Units Refurbishment project was approved by Order G-8-17 and involves the refurbishment of four generating units that are more than 100 years old. The refurbishments were completed in 2021 at an estimated total project cost of $34.180 million, inclusive of AFUDC and cost of removal. FBC is projecting approximately $0.002 million of remaining close-out costs in 2022 which will be added to rate base January 1, 2023. Overall, $32.290 million is forecast to be added to rate base by January 1, 2023 ($32.288 million of actual from 2018 to 2022 and $0.002 million of 2023 Forecast), plus $1.890 million of cost of removal, for a total estimated project cost of $34.180 million including AFUDC and cost of removal. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Refurbishment Project Final Report is included as Appendix B2.

Playmor Substation Upgrade Project

The Playmor Substation Upgrade project was approved by Order G-42-21 and involves rebuilding the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is expected to be complete in 2022 at an estimated cost of $8.036 million, inclusive of AFUDC, and approximately $0.300 million of cost of removal. As the project is expected to complete in 2022, FBC is not forecasting any capital expenditures related to this project in 2023, and all project costs, estimated to be $8.036 million (including AFUDC) are forecast to enter rate base on January 1, 2023, with $0.300 million to be recorded to cost of removal.

7.4 2023 PLANT ADDITIONS

The 2023 Plant Additions are comprised of: (i) FBC's 2023 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Forecast Capital Expenditures	$	94.428	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.248	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		94.676	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		10.918	Section 11, Schedule 5, Line 16
6	AFUDC		0.243	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.837**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN Capital Expenditures			
11	Kelowna Bulk Transformer Capacity Addition		1.710	Section 11, Schedule 5, Line 7
12	AFUDC		0.049	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		43.680	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**45.439**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**151.276**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2023, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2023 depreciation expense is calculated as $64.407 million.[46]

7.6 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[47] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

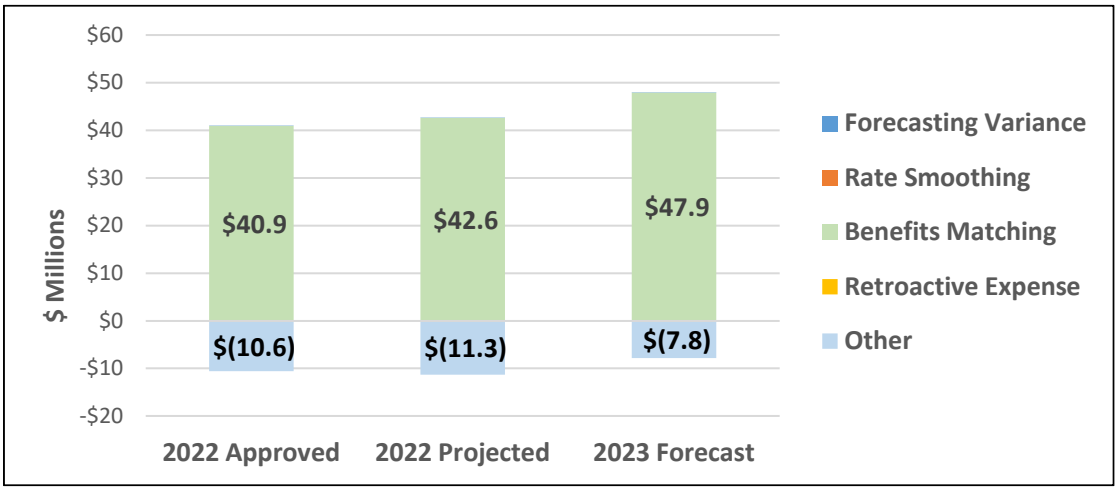
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $40.045 million. The 2023 debit balance is driven largely by the balances in the Demand Side Management (DSM) and Deferred Debt Issue Costs deferral accounts, partially offset by the Pension and OPEB Liability deferral account.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[46] $69.474 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.067 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[47] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances (rate base and non-rate base) using the approved and proposed amortization periods, the 2023 amortization expense is calculated as a credit of $3.277 million.[48] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.6.1 New Deferral Accounts

FBC is seeking approval to create one new rate base deferral account in this Application, as discussed below.

7.6.1.1 Joint Pole Use Audit 2023

Under the provisions of FBC's various joint use pole agreements, the parties are required to perform an audit of the joint use pole contacts once every five years, the last of which occurred in 2018.

Consistent with past treatment of costs for joint pole use audits, FBC is seeking approval to establish a rate base deferral account to capture costs incurred for the 2023 Joint Use Pole Audit, which are estimated at $0.435 million ($0.318 million after tax) to be incurred in 2023.

FBC is also requesting approval to amortize these costs over a five-year period beginning January 1, 2023, which represents the time period between the required audits.

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the above-described deferral account request.

[48] Section 11, Schedule 21, Column 3, Sum of Line 5 and 6.

1 **Table 7-15: Deferral Account Filing Considerations**

Item	Consideration	Joint Pole Use Audit 2023
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The 2023 Joint Pole Use Audit deferral account is a new deferral account, consistent with the past treatment of joint pole use audits in previous years.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The purpose of the requested account is to capture costs related to joint use pole audits that are required once every five years.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the MRP formula O&M since the 2018 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	An audit of joint use poles is required at five-year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	Refer to Section 7.6.1.1.
d)	any impact on intergenerational equity	FBC proposes to recover the deferred costs over the five-year period between the required audits.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	The joint use pole audit account is a cash account.

Item	Consideration	Joint Pole Use Audit 2023
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See Section 7.6.1.1.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FBC proposes to recover the deferred costs over the five-year period between the required audits.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on two existing deferral accounts and requests approval of an amortization period for one of them.

7.6.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.6.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FBC received approval through Order G-133-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FBC also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

(a) Bill payment deferrals provided to residential and small commercial customers

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FBC experienced high collection rates in regard to this program, recovering approximately 85 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.119 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FBC ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Forecast Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.563	0.005	-
Additions	0.803	-	-	-
Repayments	(0.240)	(0.444)	-	-
Transfers	-	(0.114)	(0.005)	-
Ending Balance	0.563	0.005	-	-

(b) Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.132 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FBC does not expect additional credits to be offered to customers throughout the remainder of 2022 or in 2023. As such, FBC is proposing to amortize the $0.132 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.130	0.132	0.132
Additions	0.178	0.003	-	-
Tax	(0.048)	(0.001)	-	-
Amortization[49]	-	-	-	(0.044)
Ending Balance	0.130	0.132	0.132	0.088

[49] Based on a requested three-year amortization period, as discussed in Section 7.6.2.1.2.

(c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.011	0.134	0.375
Transfers[50]	-	0.114	0.005	-
Additions[51]	0.015	0.054	0.325	-
Tax	(0.004)	(0.045)	(0.089)	-
Amortization[49]	-	-	-	(0.125)
Ending Balance	0.011	0.134	0.375	0.250

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.005 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.325 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $800 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

[50] The actual 2021 unrecoverable revenue transfers of $0.114 million consist of $0.004 million of small commercial customer balances and $0.110 million of residential customer balances.

[51] The actual 2020 unrecoverable revenue additions of $0.015 million consist of $0.014 million of small commercial customer balances and $0.001 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.054 million consist of $0.004 million of small commercial customer balances and $0.050 million of residential customer balances.

While the forecasts of the unrecovered revenue additions above rely on estimates and broader macroeconomic factors, the actual amounts that will be recorded in the deferral account will reflect actual balances that are attributable to specific customers that cannot make payment due to the COVID-19 pandemic.

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FBC has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.6.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FBC has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[52] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This, along with the improved economic conditions, although somewhat tempered recently with inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FBC has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FBC anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FBC does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FBC considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FBC may seek BCUC

[52] See Section 12.2.1 for further discussion and details.

approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.6.2.1.3 REQUEST TO DISCONTINUE REPORTING

FBC seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FBC does not see further value in providing separate detailed reporting for this account.

7.6.2.2 Indigenous Relations Agreement (Huth Substation)

As part of the Annual Review for 2020 and 2021 Rates Decision and Order G-42-21, FBC received approval to establish the Indigenous Relations Agreement (Huth Substation) deferral account to capture costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton and the impacts the substation has had on Syilx[53] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

The Huth substation is a vital component of the South Okanagan area power system, providing direct service to both FBC customers and the municipal utility of the City of Penticton. This hub is connected to five major transmission lines (42L, 49L, 47L, 52L and 53L) and to two City of Penticton distribution substations. Given the importance of the substation to the supply of power in the South Okanagan and the historical value of the land to the PIB and the Syilx people, FBC has engaged in reconciliation efforts with the PIB, consistent with the recent legislation passed by the Provincial government.

FBC stated in the 2020-2021 Annual Review that it would update its progress with respect to this matter in future annual reviews and request approval for recovery of costs captured in this deferral account once an agreement with the PIB had been reached and the impacts could be communicated.

FBC has been unable to continue preliminary discussions with the PIB on reconciliation efforts on the Huth substation. Due to impacts on the community from the COVID-19 pandemic, followed by the unique circumstances that arose in 2021 with the Kamloops Residential School findings, and as the Penticton Indian Band and FortisBC Energy Inc. are currently in discussions regarding the proposed Okanagan Capacity Upgrade project, FBC chose not to pursue further efforts regarding the Huth Substation until both parties agreed to proceed. FBC will continue to provide updates on this matter and on the deferral account in future annual review filings.

[53] The PIB is a community of the Syilx people.

7.7 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings, and inventory of materials and supplies. 2023 amounts are forecast based on 2021 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FBC requested approval of its updated 2023 and 2024 regular capital (growth, sustainment and other) forecasts; in Section 7.6.1, FBC requested approval of one new deferral account; and in Section 7.6.2, FBC discussed two existing accounts, including requesting amortization of one of these existing accounts. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN OF EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI.

FBC is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

The 2023 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 *CAPITAL STRUCTURE AND RETURN ON EQUITY*

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16; these approved capital structure and ROE values have been used to calculate rates in the Application.

8.3 *FINANCING COSTS*

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. In March 2022, FBC issued long-term debt of $100 million at a rate of 4.16 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FBC

plans to issue additional long-term debt of approximately $75 million in 2023 and will use the funds for the same purposes. The 2023 debt issuance is reflected in the financial schedules in July 2023 at a rate of 4.90 percent.[54] The exact timing, amount and rate of the 2023 issuance will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2026.[55] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-Month T-Bill forecast for 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FBC is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[54] Section 11, Schedule 27, Line 10.
[55] On July 14, 2021, the credit facility was extended to April 27, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FBC forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FBC incurs for its letters of credit under the $150 million credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2022	Projected 2022	Forecasted 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.36%	-0.36%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.18%**	**3.24%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.39%	0.44%
Renewal Fee on Undrawn Credit	0.17%	0.11%	0.12%
Other Financing Fees	0.26%	0.35%	0.44%
ST Interest Rate on Fixed Financing Fee	**0.87%**	**0.84%**	**1.00%**
FBC Short Term Rate	**1.51%**	**4.02%**	**4.24%**

Notes to Table:

[1] 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

[2] Fixed financing fees represent the costs of maintaining the $150 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[56] The Canadian Alternative Reference Rate Working Group

[56] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[57] FBC will work with its banking syndicate members to transition its credit facility agreement to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2023 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	5.44%	4.24%	3.10%	4.24%
Long Term Debt	54.56%	4.78%	3.49%	4.78%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.85%	5.73%	6.50%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2023 at the same percentages as approved for 2022. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to decrease in 2023 as compared to 2022 Approved.

[57] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2023, property taxes are forecast to increase by 2.1 percent from 2022 Approved, while income tax is forecast to decrease by 19.9 percent compared to 2022 Approved.

9.2 PROPERTY TAXES

Property taxes for 2023 of $18.260 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Generating Plant	$ 3.210	$ 3.199	$ 3.253
2	Transmission and Distribution	7.428	6.950	7.189
3	Substation Equipment	3.948	4.156	4.208
4	Land and Buildings	1.165	1.201	1.322
5	In-Lieu	2.138	2.115	2.288
6	Total Property Taxes	$ 17.889	$ 17.621	$ 18.260
7				
8	Forecast Change from 2022 Approved			2.1%
9	Forecast Change from 2022 Projected			3.6%

As shown in the above table, in 2023 property taxes are forecast to increase by 2.1 percent from 2022 Approved and increase by 3.6 percent compared to 2022 Projected. In general, the 2023 increase from 2022 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2023 as follows:

   a) Municipal rates are expected to increase by 1.0 percent;

   b) School rates are expected to decrease by 1.0 percent;

   c) Rural rates are expected to decrease by 0.4 percent;

d) Tax rates on First Nations are expected to increase by 0.8 percent; and

e) Other rates are expected to decrease by 1.4 percent.

2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to increase by 8.2 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

3. **Changes in Assessed Values.** Forecast changes in the assessed values of FBC's property are based on expected inflationary increases. These include:

a) A 5.2 percent increase in assessed values of distribution lines and a 2.5 percent increase in transmission lines;

b) A 2.5 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

c) A 0.5 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

d) Land values are expected to increase between 4.3 percent to 11.4 percent for right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered from customers in the following year.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2023 is forecast to decrease by $1.494 million or 19.9 percent compared to 2022 Approved. The 2023 Forecast decrease is primarily due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 *SUMMARY*

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 rates, it is the 2021 formula O&M and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FBC proposes to distribute a $0.911 million pre-tax credit ($0.665 million after-tax) to customers, comprised of:

- The $0.665 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 rates, and the actual 2021 deferral account after-tax credit addition of $0.665 million as provided in FBC's 2021 Annual Report to the BCUC. This amount is also shown in the opening 2023 balance[58] in the financial schedules in the Application.

FBC proposes to distribute $0.911 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance of $0.665 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

[58] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

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SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (12.546)		
3	Change in Other Revenue	(0.409)	(12.955)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	19.796		
7	Wheeling	0.894		
8	Water Fees	(0.415)	20.275	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	4.757		
12	Capitalized Overhead Change	(0.741)	4.016	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.752	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.210)		
19	Deferrals	(4.835)	(5.045)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	3.688		
23	Financing Ratio Changes	(1.049)		
24	Rate Base Growth	5.809	8.448	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.371		
28	Other Income Taxes Changes	(1.494)	(1.123)	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.368**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		409.840	Schedule 18, Line 7, Column 3
33	Rate Change		3.99%	

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Section 11

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,279,658	$ 2,375,297	$ 95,639	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	4,512	-	(4,512)	Schedule 6.1, Line 32, Column 4
3	Net Additions	105,010	134,666	29,656	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,389,180	2,509,963	120,783	
5					
6	Accumulated Depreciation Beginning	$ (659,517)	$ (693,759)	$ (34,242)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	(569)	-	569	Schedule 7.1, Line 32, Column 6
8	Net Additions	(33,657)	(47,865)	(14,208)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(693,743)	(741,624)	(47,881)	
10					
11	CIAC, Beginning	$ (232,291)	$ (243,101)	$ (10,810)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	(2,523)	-	2,523	
13	Net Additions	(11,712)	(11,628)	84	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(246,526)	(254,729)	(8,203)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 84,284	$ 89,140	$ 4,856	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	212	-	(212)	
18	Net Additions	4,857	5,067	210	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	89,353	94,207	4,854	
20					
21	Net Plant in Service, Mid-Year	$ 1,506,015	$ 1,567,697	$ 61,682	
22					
23	Adjustment for timing of Capital additions	$ 16,181	$ 22,720	$ 6,539	
24	Capital Work in Progress, No AFUDC	19,332	34,306	14,974	
25	Unamortized Deferred Charges	30,372	40,045	9,673	Schedule 11, Line 26, Column 8
26	Working Capital	6,258	6,100	(158)	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,749	4,563	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,582,907	$ 1,675,431	$ 92,524	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		38.000%	38.000%	37.000%	40.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.517%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	4.017%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,417		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,417	150,563		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,541	3,145	10,647	
16								
17	Customer Growth Factor Multiplier	G-166-20					75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17					7,985	
19								
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020					139,916	
21								
22	Average Customer Forecast - 2023 Rate Setting Purposes	Line 18 + Line 20					147,901	

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Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars		Total CapEx	Cross Reference
	(1)		(2)	(3)
1	**Forecast Capital Expenditures**			
2	Growth Capital	$	30,973	
3	Sustainment Capital		45,797	
4	Other Capital		17,658	
5	Total Forecast Capital	$	94,428	
6				
7	**Flow-Through Capital Expenditures**			
8	MRS Capital	$	-	
9	EV Charging Stations		248	
10	Total Flow-Through Capital	$	248	
11				
12	**Total Regular Capital Expenditures**	$	94,676	

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CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 5

Line No.	Particulars	2023 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	94,428	
3	Flow-Through Capital		248	
4	Total Regular Capital Expenditures	$	94,676	Schedule 4, Column 2, Line 12
5				
6	**Special Projects and CPCN's**			
7	Kelowna Bulk Transformer Capacity Addition	$	1,710	
8	Total Special Projects and CPCN's	$	1,710	
9				
10	**Total Capital Expenditures**	$	96,386	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	94,676	Line 4
16	Add - Capitalized Overheads		10,918	Schedule 20, Column 4, Line 23
17	Add - AFUDC		243	
18	Gross Capital Expenditures		105,837	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,837	
21				
22	Special Projects and CPCN's Capital Expenditures	$	1,710	Line 8
23	Add - AFUDC		49	
24	Gross Capital Expenditures		1,759	
25	Change in Work in Progress		43,680	
26	**Total Special Projects and CPCN Additions to Plant**	$	45,439	
27				
28	**Grand Total Additions to Plant**	$	151,276	Schedule 6.1, Columns 5 + 6, Line 32

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 6

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	22,045	-	-	167	(12)	22,200	
4	332	Reservoirs, Dams & Waterways	119,076	-	16,151	7,747	(782)	142,192	
5	333	Water Wheels, Turbines and Gen.	105,453	-	2	699	(142)	106,012	
6	334	Accessory Equipment	51,357	-	-	128	(38)	51,447	
7	335	Other Power Plant Equipment	48,572	-	-	5	(1)	48,576	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 348,752	$ -	$ 16,153	$ 8,746	$ (975)	$ 372,676	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,767	$ -	$ -	$ 118	$ -	$ 10,885	
13	350.1	Land Rights-Clearing	9,992	-	-	118	-	10,110	
14	353	Station Equipment	243,150	-	21,250	3,446	(305)	267,541	
15	355	Poles Towers & Fixtures	127,975	-	-	6,450	(291)	134,134	
16	356	Conductors and Devices	123,228	-	-	6,449	(313)	129,364	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 516,071	$ -	$ 21,250	$ 16,581	$ (909)	$ 552,993	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ 817	$ -	$ 8,002	
3	360.1	Land Rights-Clearing	11,630	-	-	374	-	12,004	
4	362	Station Equipment	304,310	-	8,036	13,065	(885)	324,526	
5	364	Poles Towers & Fixtures	258,898	-	-	13,410	(570)	271,738	
6	365	Conductors and Devices	436,812	-	-	20,531	(728)	456,615	
7	368	Line Transformers	193,494	-	-	14,165	(1,815)	205,844	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,459	-	-	532	-	41,991	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,178	-	-	170	(42)	14,306	
12	372	EV Stations Kiosks & Charger Connectors	5,993	-	-	-	-	5,993	
13			$ 1,284,418	$ -	$ 8,036	$ 63,064	$ (4,040)	$ 1,351,478	
14									
15		**General Plant**							
16	389	Land	$ 11,184	$ -	$ -	$ -	$ -	$ 11,184	
17	390.1	Structures - Masonry	48,652	-	-	2,785	(319)	51,118	
18	390.2	Operation Building	19,432	-	-	609	(23)	20,018	
19	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
20	391	Office Furniture & Equipment	5,399	-	-	215	(237)	5,377	
21	391.1	Computer Hardware	13,614	-	-	3,330	(3,016)	13,928	
22	391.2	Computer Software	41,906	-	-	7,033	(4,015)	44,924	
23	391.2	AMI Software	13,439	-	-	(3)	-	13,436	
24	392.1	Light Duty Vehicles	5,967	-	-	549	(484)	6,032	
25	392.1	Heavy Duty Vehciles	28,678	-	-	1,523	(351)	29,850	
26	394	Tools and Work Equipment	8,507	-	-	724	(587)	8,644	
27	397	Communication Structures & Equipment	15,707	-	-	681	(1,456)	14,932	
28	397.1	Fibre	5,729	-	-	-	(198)	5,531	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 226,056	$ -	$ -	$ 17,446	$ (10,686)	$ 232,816	
31									
32		**Total Plant in Service**	$ 2,375,297	$ -	$ 45,439	$ 105,837	$ (16,610)	$ 2,509,963	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (382)	$ -	$ 10	$ -	$ -	$ -	$ (372)	
3	331	Structures and Improvements	22,045	1.68%	5,718	-	370	(12)	-	-	6,076	
4	332	Reservoirs, Dams & Waterways	135,227	1.90%	7,278	-	2,569	(782)	(1,857)	-	7,208	
5	333	Water Wheels, Turbines and Gen.	105,455	1.79%	20,564	-	1,888	(142)	(3)	-	22,307	
6	334	Accessory Equipment	51,357	3.13%	15,121	-	1,607	(38)	(130)	-	16,560	
7	335	Other Power Plant Equipment	48,572	2.12%	20,171	-	1,030	(1)	-	-	21,200	
8	336	Roads, Railroads and Bridges	1,287	1.44%	476	-	19	-	-	-	495	
9			$ 364,905		$ 68,946	$ -	$ 7,493	$ (975)	$ (1,990)	$ -	$ 73,474	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,767	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	9,992	1.27%	2,485	-	127	-	-	-	2,612	
14	353	Station Equipment	264,400	2.33%	101,920	-	6,161	(305)	(159)	-	107,617	
15	355	Poles Towers & Fixtures	127,975	2.52%	39,342	-	3,225	(291)	(469)	-	41,807	
16	356	Conductors and Devices	123,228	2.52%	24,036	-	3,105	(313)	(469)	-	26,359	
17	359	Roads and Trails	959	1.96%	432	-	19	-	-	-	451	
18			$ 537,321		$ 168,215	$ -	$ 12,637	$ (909)	$ (1,097)	$ -	$ 178,846	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	11,630	1.25%	2,935	-	145	-	-	-	3,080	
4	362	Station Equipment	312,346	2.61%	93,321	-	8,152	(885)	(156)	-	100,432	
5	364	Poles Towers & Fixtures	258,898	2.73%	80,092	-	7,068	(570)	(567)	-	86,023	
6	365	Conductors and Devices	436,812	2.38%	129,625	-	10,396	(728)	(914)	-	138,379	
7	368	Line Transformers	193,494	3.13%	45,961	-	6,056	(1,815)	(347)	-	49,855	
8	369	Services	9,521	0.51%	6,807	-	49	-	-	-	6,856	
9	370.1	AMI Meters	41,459	6.25%	12,897	-	2,591	-	-	-	15,488	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,178	4.95%	6,259	-	702	(42)	-	-	6,919	
12	372	EV Stations Kiosks & Charger Connectors	5,993	10.00%	914	-	599	-	-	-	1,513	
13			$ 1,292,454		$ 379,748	$ -	$ 35,758	$ (4,040)	$ (1,984)	$ -	$ 409,482	
14												
15		**General Plant**										
16	389	Land	$ 11,184	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	48,652	2.53%	13,006	-	1,231	(319)	-	-	13,918	
18	390.2	Operation Building	19,432	1.63%	7,081	-	317	(23)	-	-	7,375	
19	390.1	Leasehold Improvements	2,872	1.63%	2,700	-	47	-	-	-	2,747	
20	391	Office Furniture & Equipment	5,399	4.42%	1,501	-	239	(237)	-	-	1,503	
21	391.1	Computer Hardware	13,614	21.60%	4,496	-	2,941	(3,016)	-	-	4,421	
22	391.2	Computer Software	41,906	8.96%	16,368	-	3,755	(4,015)	-	-	16,108	
23	391.2	AMI Software	13,439	10.00%	7,627	-	1,344	-	-	-	8,971	
24	392.1	Light Duty Vehicles	5,967	3.81%	2,528	-	227	(484)	77	-	2,348	
25	392.1	Heavy Duty Vehciles	28,678	6.50%	8,066	-	1,864	(351)	-	-	9,579	
26	394	Tools and Work Equipment	8,507	4.11%	3,500	-	350	(587)	-	-	3,263	
27	397	Communication Structures & Equipment	15,707	3.44%	5,067	-	540	(1,456)	(5)	-	4,146	
28	397.1	Fibre	5,729	6.97%	2,486	-	399	(198)	-	-	2,687	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,390	-	332	-	-	-	2,722	
30			$ 226,056		$ 76,850	$ -	$ 13,586	$ (10,686)	$ 72	$ -	$ 79,822	
31												
32		**Total**	$ 2,420,736		$ 693,759	$ -	$ 69,474	$ (16,610)	$ (4,999)	$ -	$ 741,624	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
3	**Total**	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
4								
5	**Amortization**							
6	Amortization	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
7	**Total**	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
8								
9	**Net CIAC**	$ 153,961	$ -	$ -	$ 6,561	$ -	$ 160,522	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 32	$ -	$ -	$ -	$ (32)	$ -	$ 16	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges	$ 2,646	$ -	$ (439)	$ -	$ -	$ 2,207	$ 2,427	Note 1
8	Demand Side Management	37,219	-	14,455	(3,903)	(5,829)	41,942	39,581	
9	Deferred Debt Issue Costs	4,074	-	600	(111)	(167)	4,396	4,235	
10	Joint Pole Use Audit 2023	-	-	435	(117)	(64)	254	127	
11	2021 Generic Cost of Capital Proceeding	675	-	450	(122)	-	1,003	839	
12	Annual Reviews for 2020-2024 Rates	154	-	200	(54)	(154)	146	150	
13	2021 Long Term Electric Resource Plan	264	-	250	(68)	(113)	333	298	
14	BCUC Initiated Inquiry Costs	109	-	100	(27)	(109)	73	91	
15	Mandatory Reliability Standards 2021 Audit	157	-	-	-	(79)	78	118	
16		$ 45,298	$ -	$ 16,051	$ (4,402)	$ (6,515)	$ 50,432	$ 47,866	
17									
18	**4. Retroactive Expense Accounts**								
19									
20	**5.Other Accounts**								
21	Pension and OPEB Liability	$ (10,592)	$ -	$ 4,664	$ -	$ -	$ (5,928)	$ (8,260)	
22	COVID-19 Customer Recovery Fund	507	-	-	-	(169)	338	423	
23	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
24		$ (10,085)	$ -	$ 4,664	$ -	$ (169)	$ (5,590)	$ (7,837)	
25									
26	**Total Rate Base Deferral Accounts**	$ 35,245	$ -	$ 20,715	$ (4,402)	$ (6,716)	$ 44,842	$ 40,045	
27									

28 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $0.851 million - transfer of $1.290 million = $(0.439) million.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	**1. Forecasting Variance Accounts**								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ 1,493	$ -	$ -	$ -	$ (604)	$ 889	$ 1,191	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	31	-	-	-	(31)	-	15	
10		$ 31	$ -	$ -	$ -	$ (31)	$ -	$ 15	
11									
12	**4. Retroactive Expense Accounts**								
13									
14	**5.Other Accounts**								
15									
16	**Total NRB Deferral Accounts at Short Term Interest**	$ 1,524	$ -	$ -	$ -	$ (635)	$ 889	$ 1,206	
17									
18	Financing Costs at STI	$ 8	$ -	$ 37	$ -	$ (8)	$ 37	$ 23	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd Schedule 12.1
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	**1. Forecasting Variance Accounts**								
4									
5	**2. Rate Smoothing Accounts**								
6									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 980	$ -	$ 450	$ -	$ -	$ 1,430	$ 1,205	
9	2017 Rate Design Application	236	-	-	-	(118)	118	177	
10	2020 - 2024 Multi-Year Rate Plan Application	290	-	-	-	(145)	145	217	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	127	-	-	-	(59)	68	98	
12		$ 1,633	$ -	$ 450	$ -	$ (322)	$ 1,761	$ 1,697	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17	US GAAP Pension and OPEB Transition Obligation	$ 348	$ -	$ (348)	$ -	$ -	$ -	$ 174	
18	Advanced Metering Infrastructure Radio-Off Shortfall	25	-	-	-	(25)	-	12	
19		$ 373	$ -	$ (348)	$ -	$ (25)	$ -	$ 186	
20									
21	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,006	$ -	$ 102	$ -	$ (347)	$ 1,761	$ 1,883	
22									
23	Financing Costs at WACD	$ 64	$ -	$ 66	$ -	$ (64)	$ 66	$ 65	

24 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	**1. Forecasting Variance Accounts**								
4	2020 - 2024 Flow-Through Deferral Account	$ (9,625)	$ -	$ -	$ -	$ 9,625	$ -	$ (4,813)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	On Bill Financing (OBF) Participant Loans	$ 1	$ -	$ (1)	$ -	$ -	$ -	$ 1	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (665)	$ -	$ -	$ -	$ 665	$ -	$ (333)	
15									
16	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (10,289)	$ -	$ (1)	$ -	$ 10,290	$ -	$ (5,145)	
17									
18	Financing Costs at AFUDC	$ (757)	$ -	$ (317)	$ -	$ 757	(317)	(537)	
19									
20	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
21									
22									
23	**Total Non Rate Base Deferral Accounts (including financing)**	**$ (7,394)**	**$ -**	**$ (113)**	**$ -**	**$ 9,993**	**$ 2,487**	**$ (2,455)**	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 7,065	$ 6,850	$ (215)	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	329	353	24	
6	Employee Loans	443	570	127	
7	Inventories - Materials and Supplies	612	649	37	
8	Employee Withholdings	(2,191)	(2,322)	(131)	
9	Total	$ 6,258	$ 6,100	$ (158)	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 205,868	56.0	$ 11,528,608		
4	Commercial Tariff Revenue	110,473	45.1	4,982,332		
5	Wholesale Tariff Revenue	54,109	37.5	2,029,088		
6	Industrial Tariff Revenue	49,767	38.0	1,891,146		
7	Lighting Tariff Revenue	2,295	34.6	79,407		
8	Irrigation Tariff Revenue	3,696	47.0	173,712		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,108	90.0	$ 549,720		
12	Contract Revenue	2,367	62.2	147,227		
13	Transmission Access Revenue	1,834	65.2	119,577		
14	Late Payment Charges	994	54.0	53,658		
15	Connection Charges	553	30.5	16,867		
16	Other Utility Income	385	63.4	24,409		
17	Total	$ 438,449		$ 21,595,751		49.3
18						
19	**EXPENSES**					
20	Power Purchases	$ 163,575	(51.5)	$ (8,424,126)		
21	Wheeling	6,987	(46.9)	(327,699)		
22	Water Fees	11,543	(1.4)	(16,160)		
23	Operating and Maintenance	61,871	(28.6)	(1,769,501)		
24	Property Taxes	18,260	(4.9)	(89,474)		
25	GST	593	(45.4)	(26,900)		
26	Income Tax	6,005	(15.2)	(91,276)		
27	Total	$ 268,833		$ (10,745,136)		(40.0)
28						
29	Net Lag (Lead) Days					9.3
30	Total Expenses				$	268,833
31						
32	Cash Working Capital				$	6,850

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s) Schedule 16

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	Revised Revenue	2023 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,306	3,476	-	3,476	170	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 397,294	$ 409,840	$ -	$ 409,840	$ 12,546	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	16,368	16,368	16,368	
7	Total	397,294	409,840	16,368	426,208	28,914	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 161,830	$ 182,105	$ -	$ 182,105	$ 20,275	Schedule 19, Line 30, Column 3
11	O&M Expense (net)	57,855	61,871	-	61,871	4,016	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	63,609	61,316	-	61,316	(2,293)	Schedule 21, Line 11, Column 3
13	Property Taxes	17,889	18,260	-	18,260	371	Schedule 22, Line 6, Column 3
14	Other Revenue	(11,832)	(12,241)	-	(12,241)	(409)	Schedule 23, Line 9, Column 3
15	Utility Income Before Income Taxes	107,943	98,529	16,368	114,897	6,954	
16							
17	Income Taxes	7,499	1,589	4,416	6,005	(1,494)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 100,444	$ 96,940	$ 11,952	$ 108,892	$ 8,448	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,582,907	$ 1,675,028		$ 1,675,431	$ 92,524	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.35%	5.79%		6.50%	0.15%	Schedule 26, Line 5, Column 6

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VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,283	1,301	18	
3	Commercial	946	973	27	
4	Wholesale	560	578	18	
5	Industrial	470	575	105	
6	Lighting	10	9	(1)	
7	Irrigation	37	39	2	
8	Total	3,306	3,476	170	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 195,058	$ 197,962	$ 2,904	
12	Commercial	104,380	106,230	1,850	
13	Wholesale	51,255	52,031	776	
14	Industrial	40,804	47,856	7,052	
15	Lighting	2,411	2,207	(204)	
16	Irrigation	3,386	3,554	168	
17	Total	$ 397,294	$ 409,840	$ 12,546	

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REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 18

Line No.	Particulars	2022 Approved Revenue	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 195,058	$ 197,962	$ 7,906	$ 205,868	130,787	1,301	
2	Commercial	104,380	106,230	4,243	110,473	17,267	973	
3	Wholesale	51,255	52,031	2,078	54,109	6	578	
4	Industrial	40,804	47,856	1,911	49,767	42	575	
5	Lighting	2,411	2,207	88	2,295	1,358	9	
6	Irrigation	3,386	3,554	142	3,696	1,103	39	
7	Total	$ 397,294	$ 409,840	$ 16,368	$ 426,208	150,563	3,476	
8								
9	**Effective Increase**			3.99%				

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COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,591	3,775	184	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,841	$ 44,050	$ 2,209	
6	BC Hydro PPA	44,062	71,302	27,240	
7	Waneta Expansion	42,701	41,834	(867)	
8	Market and Contracted Producers	15,102	6,326	(8,776)	
9	Independent Power Producers	73	62	(11)	
10	Self-Generators	-	-	-	
11	CPA Balancing Pool	-	-	-	
12	Total	$ 143,779	$ 163,575	$ 19,796	
13					
14	**WHEELING**				
15	**Wheeling Nomination (MW months)**				
16	Okanagan Point of Interconnection	2,475	2,670	195	
17	Creston	420	420	-	
18					
19	**Wheeling Expense**				
20	Okanagan Point of Interconnect	$ 4,903	$ 5,555	$ 652	
21	Creston	542	570	28	
22	Other	648	863	215	
23	Total	$ 6,093	$ 6,987	$ 894	
24					
25	**WATER FEES**				
26	Plant Entitlement Use in previous year (GWh)	1,679	1,571	(108)	
27					
28	Water Fees	$ 11,958	$ 11,543	$ (415)	
29					
30	Total	$ 161,830	$ 182,105	$ 20,275	

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Schedule 20

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 455			
3	2023 Net Inflation Factor	4.017%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 473			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	147,901			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 69,957			Line 4 x Line 6 / 1,000
9					
10	2021 Average Customer True-up	509			
11					
12	2023 Inflation Indexed O&M	$ 70,466		$ 70,466	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (1,297)		
16	Insurance Premiums		2,457		
17	BCUC Levies		385		
18	MRS		585		
19	EV Charging Stations		193		
20	Sub-total		$ 2,323	2,323	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 72,789	Line 12 + Line 20
23	Capitalized Overhead			(10,918)	-15 % x Line 22
24	**Net O&M Expense**			$ 61,871	Sum of Lines 22 and 23

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s) Schedule 21

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 66,722	$ 69,474	$ 2,752	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 5,913	$ 6,716	$ 803	Schedule 11, Line 26, Column 6
6	Non-Rate Base Deferrals	(4,355)	(9,993)	(5,638)	Schedule 12.2, Line 23, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,857)	(5,067)	(210)	Schedule 9, Line 7, Column 5
9		(3,113)	(8,158)	(5,045)	
10					
11	Total	$ 63,609	$ 61,316	$ (2,293)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,210	$ 3,253	$ 43	
2	Transmission and Distribution	7,428	7,189	(239)	
3	Substation Equipment	3,948	4,208	260	
4	Land and Buildings	1,165	1,322	157	
5	1% In-Lieu of Municipal Taxes	2,138	2,288	150	
6	Total	$ 17,889	$ 18,260	$ 371	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,018	$ 6,108	$ 90	
2	Contract Revenue	2,277	2,367	90	
3	Transmission Access Revenue	1,771	1,834	63	
4	Interest Income	20	30	10	
5	Late Payment Charges	875	994	119	
6	Connection Charges	505	553	48	
7	Other Recoveries	366	355	(11)	
8	EV Carbon Credits	-	-	-	
9	Total	$ 11,832	$ 12,241	$ 409	

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Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 100,444	$ 108,892	$ 8,448	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(42,510)	(47,571)	(5,061)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(37,660)	(45,084)	(7,424)	Line 32
4	Accounting Income After Tax	$ 20,274	$ 16,237	$ (4,037)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 27,773	$ 22,242	$ (5,531)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,499	$ 6,005	$ (1,494)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 7,499	$ 6,005	$ (1,494)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 66,722	$ 69,474	$ 2,752	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	1,558	(3,277)	(4,835)	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	84	(528)	(612)	
22	OPEB Expense	1,607	1,119	(488)	
23					
24	Deductions:				
25	Capital Cost Allowance	(86,398)	(89,854)	(3,456)	Schedule 25, Line 19, Column 6
26	CIAC Amortization	(4,857)	(5,067)	(210)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,419)	(4,203)	216	
28	OPEB Contributions	(655)	(705)	(50)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,177)	(10,918)	(741)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (37,660)	$ (45,084)	$ (7,424)	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions & Opening Adjt	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 154,085	$ -	$ -	$ (6,163)	$ 147,922
2	1(b)	6%	33,091	3,043	1,521	(2,259)	33,875
3	2	6%	11,403	-	-	(684)	10,719
4	3	5%	648	-	-	(32)	616
5	6	10%	2	-	-	-	2
6	8	20%	3,694	842	421	(991)	3,545
7	10	30%	4,709	1,857	929	(2,250)	4,316
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,926	-	-	(485)	6,441
10	14.1 (post 2016)	5%	3,951	1,280	640	(294)	4,937
11	17	8%	156,652	22,036	11,018	(15,177)	163,511
12	42	12%	9,649	610	305	(1,268)	8,991
13	43.1	30%	566	(155)	-	(123)	288
14	45	45%	1	-	-	-	1
15	46	30%	2,708	-	-	(812)	1,896
16	47	8%	494,831	87,737	43,868	(50,115)	532,453
17	50	55%	2,800	9,286	4,643	(9,201)	2,885
18							
19	Total		$ 885,727	$ 126,536	$ 63,345	$ (89,854)	$ 922,409
20							

21 * Note - Accelerated Investment Incentive Property

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 41,155	$ 914,178	54.56%	4.78%	2.61%	$ 43,709	$ 2,554	Schedule 27, Line 12, Column 6
2	Short Term Debt	1,355	91,081	5.44%	4.24%	0.23%	3,862	2,507	
3	Common Equity	57,934	670,172	40.00%	9.15%	3.66%	61,321	3,387	
4									
5	Total	$ 100,444	$ 1,675,431	100.00%		6.50%	$ 108,892	$ 8,448	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1993 Debt Issue - Series G	August 28, 1993	August 28, 2023	$ 16,370	8.800%	$ 1,441	
2	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
3	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
4	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
5	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
6	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
7	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
8	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
9	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
10	2023 Debt Issue - MTN - 23	July 1, 2023	July 1, 2053	37,808	4.900%	1,853	
11							
12	Total			$ 914,178		$ 43,709	
13							
14	Average Embedded Cost				4.78%		

12. ACCOUNTING MATTERS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FBC discusses "Exogenous Factors" under its MRP, providing an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC provides information on the Flow-through deferral account.

12.2 *EXOGENOUS (Z) FACTORS*

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Rates, FBC identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FBC's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account.[59] FBC also stated in the Annual Review for 2020 and 2021 Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Rates application, FBC provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions). In the following section, FBC reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

[59] FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FBC has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its system safely and reliably. This has resulted in net incremental O&M impacts.

12.2.1.1 FBC Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FBC's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. As a result, this makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FBC has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FBC has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Costs

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease by approximately $1.03 million in FBC's net incremental O&M expense (costs less cost reductions).

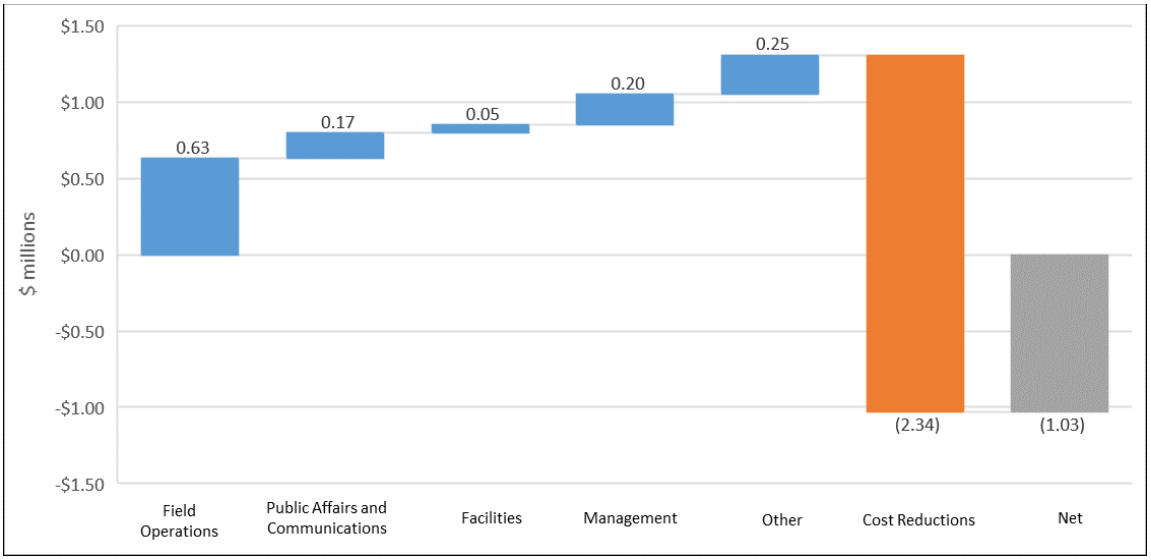
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.46	$ 0.18	$ 0.63
Public Affairs and Communications	$ 0.16	$ 0.01	$ 0.17
Facilities	$ 0.04	$ 0.01	$ 0.05
Management	$ 0.10	$ 0.10	$ 0.20
Other	$ 0.18	$ 0.07	$ 0.25
Total Direct Costs	$ 0.94	$ 0.36	$ 1.31
Cost Reductions	$ (1.05)	$ (1.29)	$ (2.34)
Net difference	$ (0.10)	$ (0.93)	$ (1.03)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these costs were more than offset by lower employee related expenses. In 2020 and 2021, FBC incurred approximately $1.31 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FBC's customers, employees, and their communities, and to continue to operate the system safely and reliably. The incremental costs were offset by approximately $2.34 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FBC COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FBC incurred approximately $0.63 million related to the COVID-19 pandemic, with the majority of the costs related to the sequestering of system control centre employees from having to return to their homes and separation of the operators between the system control centre and Kootenay operating centre sites to ensure a safe and healthy work environment for this critical function. FBC also incurred costs for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FBC incurred approximately $0.17 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FBC incurred approximately $0.05 million for Facilities-related resources and activities including safety supplies, additional cleaning, first aid coverage, and signage.

Under the category of Management, approximately $0.20 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications, and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators, and organizations like Emergency Management BC.

The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FBC achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $2.34 million.

12.2.1.3.3 CUMULATIVE NET IMPACT

The variances for the 2020 and 2021 net incremental O&M (costs less cost reductions) total to a net decrease of approximately $1.03 million.

Accordingly, FBC requests approval to return the exogenous factor savings of $1.03 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FBC does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FBC's 2022 Annual Review, FBC started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FBC, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FBC accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Rates, FBC proposed (and was approved by Order G-42-21) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FBC's original proposal, FBC has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those O&M actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.6.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FBC has included the O&M savings shown above in the 2022 Flow-through projection provided in Table 12-3 below, on Line 15, so that the net amount will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FBC seeks a variance to Directive 6 of Order G-42-21. FBC requests that Directive 6 be varied as followed: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FBC proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral Account, the cumulative net variance of the net incremental O&M (costs less reductions) of $1.03 million in 2023.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FBC provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FBC follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FBC has made use of an exemption from the Ontario Securities Commission (OSC) permitting FBC to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FBC also has the option to obtain an exemption permitting the use of US GAAP by

qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FBC sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FBC's original exemption from 2011 was filed jointly with FBC's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FBC obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FBC's use of US GAAP for regulatory accounting purposes since 2011.[60] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following:[61]

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC considers that the intention of the above direction was to ensure that FBC has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FBC would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FBC has approval from the BCUC to use US GAAP for regulatory accounting purposes, FBC is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FBC plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

[60] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[61] Order G-83-14, Directive 2.

In the following section, FBC provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-2: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $5.007 million credit is shown in Table 12-3 below. To calculate the amount to be distributed to customers, FBC has also included the following adjustment:

- The $4.618 million credit difference between the projected ending 2021 deferral account credit balance of $3.927 million[62] embedded in 2022 rates, and the actual ending 2021 deferral credit balance of $8.545 million. A more detailed breakout of the 2021 variance is provided in Table 12-4 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 18.

Table 12-3: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (397.294)	$ (414.292)	$ (16.998)
2				
3	**Total Power Purchase Expense**	143.779	153.164	9.385
4				
5	**Total Wheeling**	6.093	6.330	0.237
6				
7	**Total Water Fees**	11.958	11.916	(0.042)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.223	2.291	0.068
12	BCUC Fees	0.373	0.373	-
13	MRS	0.765	0.500	(0.265)
14	EV DCFC	0.187	0.187	-
15	COVID-19 Pandemic	-	(1.030)	(1.030)
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	17.889	17.621	(0.268)
24				
25	**Other Revenues**			
26	EV Carbon Credits	-	(0.625)	(0.625)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.155	41.794	0.639
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
31	Short-term debt rate variance	-	2.253	2.253
32	Short-term debt volume variance from long-term debt issue variance	-	(1.005)	(1.005)
33	Short-term debt timing variance from long-term debt issue timing	-	0.793	0.793
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.852	1.852
39				
40	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(5.007)**
41				
42	2021 Ending Deferral Account Balance True-up			(4.618)
43				
44	**2023 After-Tax Amortization**			**(9.625)**

[62] FBC Annual Review for 2022 Rates, Compliance Filing financial schedules, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2022 Projected flow-through variances shown in Table 12-3 above:

- The variance in revenue is due to increased industrial, commercial, wholesale and residential loads;
- The variance in power purchase expense is primarily due to an increase in gross load. Increasing gross load drove additional market purchases as well as BC Hydro PPA energy and capacity purchases at a higher than anticipated total cost. Rising rates further contributed to the increase in power purchase expense;
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC issuing long-term debt later in 2022 than forecast, but at a higher amount and higher rate than forecast, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FBC is also providing a breakdown of the 2021 true-up amount of $4.618 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (389.100)	$ (404.247)	$ (15.147)
2				
3	**Total Power Purchase Expense**	141.747	152.473	10.726
4				
5	**Total Wheeling**	5.836	6.000	0.164
6				
7	**Total Water Fees**	10.878	10.741	(0.137)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	0.775	0.775	-
11	Insurance	2.022	1.924	(0.098)
12	BCUC Fees	0.350	0.350	-
13	MRS	0.100	0.052	(0.048)
14	2021 Wildfires	0.155	0.155	-
15	Capitalized Overhead	(9.795)	(9.795)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	5.110	5.110	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.301)	(0.301)
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	17.225	17.262	0.037
23				
24	**Interest Expense**			
25	Long-term debt interest expense variance	40.698	40.251	(0.447)
26	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.059)	(0.059)
27	Short-term debt rate variance	(0.500)	(0.593)	(0.092)
28	Short-term debt volume variance from long-term debt issue variance	-	0.303	0.303
29	Short-term debt timing variance from long-term debt issue timing	0.910	-	(0.910)
30				
31	**Income Tax Expense**			
32	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.048	0.048
33	Income tax/CCA rate changes	-	-	-
34	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.571	3.097	1.526
35				
36	EV DCFC Service Application 2018-2021 adjustment	0.107	(0.074)	(0.181)
37				
38	**2021 Ending Deferral Account Balance True-up**			**(4.618)**

The 2021 Actual variances shown in Table 12-4 above are described as follows:

- The favourable variance in revenue of $15.147 million was due to higher than projected residential, commercial, wholesale and irrigation loads, mainly due to weather variations. Favourable variances in residential ($12.209 million), commercial ($2.614 million), wholesale ($1.552 million), and irrigation ($0.815 million) revenue were partially offset by unfavourable variances in industrial ($1.939 million) and lighting ($0.104 million) revenue;
- The increase in power purchase expense of $10.726 million was due several factors including increased market expenses, increased load, and reduced generation availability. Increased load and market expenses were primarily due to several extreme weather events, such as the June 2021 heat dome event. This increase was partially offset by increased surplus capacity sales under the CEPSA Agreement;
- The increase in wheeling costs of $0.164 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;
- The decrease in water fees of $0.137 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.146 million lower than projected, with all items comparable to the projected amounts;
- Actual property tax expense was relatively consistent with the projected amount;
- The variance between the actual (0.81 percent) and projected (1.03 percent) short-term debt interest rates results in an amount to be returned to customers of $0.092 million,[63] shown on Line 27 of the table above. The long-term debt interest expense variance of $0.447 million to be returned to customers is due to the projected 2021 long-term debt issuance not actually occurring. The net variance of $0.607 million to be returned to customers on Lines 28 and 29 of Table 12-4 above is due to the impact of a lower actual short-term interest rate than projected, partially offset by the delay in the 2021 long-term debt issuance;
- The unfavourable income tax variance of $1.526 million is calculated as 27 percent of the aforementioned variances;
- The favourable variance of $0.181 million for the EV DCFC Service Application 2018-2021 adjustment relates to the true-up of the 2021 cost of service amounts. As discussed in the Compliance Filing to the 2022 Annual Review Decision, FBC estimated the 2018-2021 EV cost of service amounts to be a $0.107 million debit recoverable from customers, using the 2018-2020 actual cost of service amounts and a 2021 projected amount. The actual 2021 EV cost of service was lower than projected, mainly related to favourable taxes, resulting in the $0.181 million overall credit true-up amount to be returned to customers; and
- The combined favourable variance of $0.312 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 19, 20, 26 and 32, respectively, were derived for 2021 by comparing the actual 2021 cost of service impacts of the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FBC has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic exogenous factor to customers in 2023 through inclusion in the Flow-through deferral account. FBC has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[63] (0.81% - 1.03%) x $42.042 million forecast 2021 short-term debt in Schedule 26 of October 28, 2020 Evidentiary Update financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FBC reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[64] FBC has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2022 SQI performance in the Annual Review for 2024 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Rates.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FBC's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[64] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs."

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2021 Results	June 2022 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	93%	95%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	0.67	0.80
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.12	0.14
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%	63%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	65	98
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[65]	4.52	4.27	2.94
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	2.08	1.58
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.23%	0.85%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%	99.91%

[65] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2021 result was 93 percent which met the benchmark. The June 2022 year-to-date performance is 95 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	95%
Benchmark	93%								
Threshold	90.6%								

13.2.1.2 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2021 (three-year rolling average) result was 0.67 which was better than the benchmark of 1.64. The 2021 annual AIFR was 0.89 which reflected 3 Medical Treatments and 1 Lost Time Injury.

The June 2022 year-to-date performance (three-year rolling average) result is 0.80 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.25 and reflects 2 Medical Treatments and 1 Lost Time Injury.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	1.25
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	0.80
Benchmark	1.64								
Threshold	2.39								

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2021 result was 82 percent which was better than the benchmark of 78 percent. The June 2022 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	78%
Benchmark	78%								
Threshold	72%						74%		

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2021 result was 0.12 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.14, which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2021 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-99.99885%)	0.06

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.60%	(100%-PA)*100	=(100%-99.69%)*100	0.31
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06+0+0.31) /3	0.12

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2021 result was 99 percent, which was better than the benchmark of 98 percent. The June 2022 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%		
Threshold	94%						96%		

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2021 result was 70 percent which met the benchmark. The June 2022 year-to-date performance is 63 percent, which is below the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with colder weather that resulted in approximately 27 percent more high bill inquiries in the first quarter than the average of the preceding two years[66]. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 20 percent of its Customer Service Representatives in 2021.[67] All exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FBC accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While

[66] FBC experienced approximately 1,000 high bill inquiries in Q1 2022 which compares to an average of approximately 790 in the first quarter for the two-year period 2020-2021.

[67] On average, FBC has approximately 20 customer service representatives, and 4 left the organization in the latter part of 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

some success has been achieved, FBC has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical, carrying into April instead of early March. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with a higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, the recovery of the non-emergency TSF remains a focus, with FBC expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	63%
Benchmark	70%								
Threshold	68%								

13.2.2.5 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly, and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The annual CSI score for 2021 was 8.4, slightly lower than that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The score for overall satisfaction, which has the highest weighting, decreased from 8.5 in 2020 to 8.4 in 2021. The scores for satisfaction with the energy conservation information and contact centre metrics decreased from 7.6 in 2020 to 7.5 in 2021, and 8.5 in 2020 to 8.4 in 2021, respectively. In addition, the scores for the satisfaction with the accuracy of meter reading and field services metrics remained static at 8.2 and 9.0 in 2021, respectively.

The score for 2022 year-to-date is 8.4, consistent with the annual score recorded for 2021. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area, lower in one, and static in three when compared to the annual 2021 scores. The score for the satisfaction with the accuracy of meter reading metric increased from 8.2 to 8.3. The score for the satisfaction with field services metric decreased from 9.0 to 8.8. The scores for the overall satisfaction, energy conservation information, and contact centre metrics were static at 8.4, 7.5 and 8.4, respectively, from results achieved in 2021. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4
Benchmark	n/a								
Threshold	n/a								

13.2.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2021 result was 65 seconds, and the June 2022 year-to-date performance is 98 seconds.

As with previous years, 2021 remained within a reasonable range from a customer experience perspective in that, on average, calls to the contact centre were answered in and around the one-minute mark. With respect to 2022, the year-to-date performance reflects the challenging circumstances in the first quarter of the year described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA back towards normal performance is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.[68]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	226	49	48	49	49	49	71	65	98
Benchmark	n/a								
Threshold	n/a								

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

[68] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

13.2.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 4.27 which was better than the threshold of 4.52 but below the benchmark of 3.22. The June 2022 year-to-date performance is 2.94 which is better than the benchmark. The 2021 results were negatively impacted by multiple external factors which did not meet the threshold for normalization.

The July 2021 results were nearly five times the three-year average and were heavily influenced by several factors that did not meet the threshold for normalization. The largest single event that influenced the July results was the collapse of a construction crane on July 12 in downtown Kelowna. The immediate response to this event was to de-energize a large portion of the surrounding area so that first responders could safely attend to the scene. This incident interrupted power to over 2,600 customers and accounted for over 36,000 customer hours interrupted.

British Columbia also experienced an unprecedented run of extreme heat at the end of June and early July which dried forest fuels earlier than usual and led to one of the worst fire seasons on record. FBC transmission and distribution infrastructure were both impacted by the wildfires with dozens of structures burned to the ground. The largest single outage due to these fires was in the Oliver area and contributed over 21,000 customer hours to July.

In addition to the damaged infrastructure, FBC Operations proactively de-energized portions of the system at the request of BC Wildfire Services to assist in fire suppression efforts. System operations were also impacted by proactively disabling automatic line reclosing in parts of the system to reduce the risk of igniting a fire from trees contacting FBC lines. This led to larger and longer outages in areas of the system where automatic line reclosing was disabled to allow field crews time to assess the cause and confirm that it was safe to re-energize the system. FBC estimates that the combination of fire damage, proactive de-energization, and disabling of automatic line reclosing contributed to over 52,000 customer hours of interruption in July.

There were three Major Event Days that met the threshold for normalization in 2021:

- On January 13, a major windstorm across the Okanagan and Kootenays caused approximately 11,000 customer-interruptions and totalled over 155,000 customer-hours of interruption.
- On April 18, a major windstorm across the West Kootenays qualified for a Major Event Day causing approximately 19,800 customer-interruptions and totalled over 200,800 customer-hours of interruption.
- On November 15, a major storm affected multiple areas in the Okanagan causing approximately 27,474 customer-interruptions and totalled over 218,720 customer-hours of interruption. This event is the highest total customer-hours of interruption FBC has on record (back to 2003).

There have been no Major Event Days in 2022 to-date.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[69]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.94
Benchmark	2.22						3.22		
Threshold	2.62						4.52		

13.2.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

[69] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The 2021 result was 2.08 and the June 2022 year-to-date performance is 1.58, with both better than the threshold of 2.19. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires and storms that were discussed in the SAIDI section. FBC also completed system upgrades on several radial transmission lines where no alternate supply was available which impacted a large number of customers. These outages were scheduled in advance during "off peak" hours to minimize the impact to homes and businesses.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[70]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.58
Benchmark	1.64						1.57		
Threshold	2.50						2.19		

13.2.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

The 2021 result for GFOR was 0.23 percent. The June 2022 year-to-date performance is 0.85 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

[70] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.23%	0.85%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.60	TBD	

13.2.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are twelve points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The 2021 result of 99.90 percent and June 2022 year-to-date result of 99.91 percent are generally consistent with prior years' results. The City of Nelson interconnection at Coffee Creek was negatively impacted by two of the three Major Events on the FBC system described previously in the SAIDI section. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.91%
Benchmark	n/a								
Threshold	n/a								

13.3 *SUMMARY*

In summary, FBC's 2021 and June 2022 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A
LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	**Reference period**	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: British Columbia Two-Year Outlook 2022

Key Economic Indicators: British Columbia, 2021-23															
(forecast completed February 18, 2022)															
	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4	2023Q1	2023Q2	2023Q3	2023Q4	2021	2022	2023
GDP at market prices ($ millions)	328,577	329,385	334,551	339,673	343,417	348,045	350,673	353,935	356,447	359,588	361,919	364,178	333,047	349,017	360,533
	1.5	*0.2*	*1.6*	*1.5*	*1.1*	*1.3*	*0.8*	*0.9*	*0.7*	*0.9*	*0.6*	*0.6*	*7.7*	*4.8*	*3.3*
GDP at market prices (2012 $ millions)	278,978	277,225	279,564	281,275	283,897	288,030	290,551	293,351	295,260	297,122	298,139	299,057	279,261	288,957	297,395
	0.7	*-0.6*	*0.8*	*0.6*	*0.9*	*1.5*	*0.9*	*1.0*	*0.7*	*0.6*	*0.3*	*0.3*	*4.7*	*3.5*	*2.9*
GDP at basic prices (2012 $ millions)	258,225	257,607	258,824	259,977	262,651	266,678	269,275	272,107	273,828	275,566	276,523	277,352	258,659	267,678	275,817
	0.5	*-0.2*	*0.5*	*0.4*	*1.0*	*1.5*	*1.0*	*1.1*	*0.6*	*0.6*	*0.3*	*0.3*	*4.8*	*3.5*	*3.0*
Consumer price index (2002 = 1.000)	1.342	1.354	1.370	1.380	1.401	1.412	1.424	1.433	1.441	1.449	1.456	1.463	1.361	1.418	1.452
	0.9	*0.9*	*1.2*	*0.7*	*1.6*	*0.7*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*2.8*	*4.1*	*2.5*
Implicit price deflator—GDP at market prices	1.178	1.188	1.197	1.208	1.210	1.208	1.207	1.207	1.207	1.210	1.214	1.218	1.193	1.208	1.212
(2012 = 1.000)	*0.8*	*0.9*	*0.7*	*0.9*	*0.2*	*-0.1*	*-0.1*	*0.0*	*0.1*	*0.2*	*0.3*	*0.3*	*2.9*	*1.3*	*0.4*
Wages and salary per employee ($ 000s)	54.6	55.5	56.8	57.2	57.3	57.2	57.3	57.6	57.9	58.1	58.5	58.8	56.0	57.3	58.3
	1.2	*1.7*	*2.2*	*0.8*	*0.1*	*-0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*4.1*	*2.3*	*1.7*
Primary household income ($ millions)	232,341	235,256	242,425	248,720	249,890	251,061	252,734	254,925	256,921	259,217	261,239	263,382	239,685	252,153	260,190
	1.9	*1.3*	*3.0*	*2.6*	*0.5*	*0.5*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*9.1*	*5.2*	*3.2*
Household disposable income ($ millions)	210,080	211,206	215,909	216,925	215,827	216,553	218,063	219,981	220,758	222,983	224,889	226,886	213,530	217,606	223,879
	1.2	*0.5*	*2.2*	*0.5*	*-0.5*	*0.3*	*0.7*	*0.9*	*0.4*	*1.0*	*0.9*	*0.9*	*2.4*	*1.9*	*2.9*
Household net savings rate (per cent)	7.3	7.8	4.5	4.2	3.3	2.9	3.1	3.3	2.8	2.8	2.6	2.5	6.0	3.1	2.7
Population (000s)	5,164	5,186	5,215	5,250	5,259	5,268	5,276	5,284	5,296	5,307	5,320	5,332	5,204	5,272	5,314
	0.1	*0.4*	*0.6*	*0.7*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*1.3*	*0.8*
Employment (000s)	2,629	2,631	2,669	2,696	2,694	2,685	2,690	2,698	2,704	2,714	2,718	2,723	2,656	2,692	2,715
	1.6	*0.1*	*1.4*	*1.0*	*-0.1*	*-0.3*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.2*	*6.6*	*1.3*	*0.9*
Labour force (000s)	2,836	2,825	2,846	2,852	2,850	2,858	2,866	2,872	2,877	2,882	2,887	2,892	2,840	2,862	2,884
	1.4	*-0.4*	*0.8*	*0.2*	*-0.1*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*3.7*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.6	65.2	65.3	65.0	64.8	64.8	64.9	64.8	64.8	64.7	64.7	64.7	65.3	64.8	64.7
Unemployment rate (per cent)	7.3	6.9	6.2	5.5	5.5	6.1	6.1	6.0	6.0	5.8	5.8	5.8	6.5	5.9	5.9
Retail sales ($ millions)	98,731	99,233	98,267	96,315	95,494	95,987	96,084	97,049	97,750	98,331	99,140	99,888	98,136	96,153	98,777
	3.7	*0.5*	*-1.0*	*-2.0*	*-0.9*	*0.5*	*0.1*	*1.0*	*0.7*	*0.6*	*0.8*	*0.8*	*12.1*	*-2.0*	*2.7*
Housing starts (units, 000s)	52,902	49,795	45,224	42,507	40,000	39,536	36,171	35,850	35,530	35,209	34,889	34,568	47,607	37,889	35,049
	30.7	*-5.9*	*-9.2*	*-6.0*	*-5.9*	*-1.2*	*-8.5*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*26.2*	*-20.4*	*-7.5*
Net interprovincial migration (000s)	16.7	17.4	17.7	31.4	15.2	10.4	7.1	5.2	7.9	7.5	7.1	6.8	20.8	9.5	7.3
Net international migration (000s)	52.6	52.2	19.8	18.8	20.9	22.2	24.4	27.3	35.2	38.2	40.3	41.6	35.8	23.7	38.8
Shaded area represents forecast data, *italics indicate percentage change*.															
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.															
For each indicator, the first line is the level and the second line is the percentage change from the previous period.															
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.															

Note: Table above is from the Conference Board of Canada, British Columbia Two-Year Outlook, March 30, 2022.

Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 show 10 years of historical data and the before-savings and after-savings forecast for 2022S and 2023F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2023F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2016 to 2021 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2016. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2019 to 2021. Finally, Table 6.6 shows the system load factor from the years 2016 to 2021 and the forecast load factor for 2022S and 2023F.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2021.
- after-savings – the load after DSM and includes Normalized loads to December 2021.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
2021	378,637	338,019	319,817	276,739	257,155	259,320	306,943	294,834	257,175	285,567	334,065	368,654	3,676,926
Before-Savings													
2022S	393,190	335,138	331,640	280,553	267,153	271,396	321,383	310,626	274,609	295,951	337,171	383,507	3,802,317
2023F	396,339	337,950	334,411	282,950	269,568	273,870	324,232	313,473	277,139	298,596	340,037	386,627	3,835,192
After-Savings													
2022S	390,444	332,413	328,981	277,979	264,668	268,968	318,980	308,194	272,123	293,371	334,512	380,802	3,771,436
2023F	390,866	332,540	329,150	277,874	264,687	269,119	319,544	308,746	272,326	293,617	334,927	381,448	3,774,844

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
2021	345,746	308,157	294,337	255,440	238,210	239,708	282,793	272,125	237,826	263,832	306,218	337,045	3,381,436
Before-Savings													
2022S	356,872	305,644	305,096	260,549	249,414	252,595	296,341	287,118	255,390	274,469	309,030	348,812	3,501,329
2023F	359,759	308,223	307,659	262,783	251,668	254,896	298,970	289,745	257,738	276,922	311,668	351,673	3,531,705
After-Savings													
2022S	354,335	303,127	302,639	258,171	247,118	250,352	294,120	284,871	253,093	272,084	306,573	346,312	3,472,795
2023F	354,702	303,224	302,798	258,093	247,157	250,505	294,638	285,378	253,291	272,322	306,947	346,888	3,475,944

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
Before-Savings													
2022S	149,350	118,436	116,520	92,400	89,399	86,970	106,340	99,003	84,580	98,837	120,281	146,323	1,308,438
2023F	149,488	118,545	116,628	92,485	89,481	87,050	106,438	99,094	84,658	98,928	120,392	146,458	1,309,643
After-Savings													
2022S	148,891	117,988	116,106	92,031	89,075	86,679	106,062	98,712	84,257	98,468	119,867	145,876	1,304,011
2023F	148,568	117,647	115,796	91,743	88,830	86,464	105,876	98,507	84,003	98,180	119,551	145,549	1,300,714

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
2021	88,860	79,418	80,125	72,153	73,680	74,618	79,949	69,139	96,038	76,264	81,554	87,844	959,641
Before-Savings													
2022S	91,281	81,781	81,825	71,225	73,270	74,552	85,487	85,537	76,428	79,040	83,178	90,148	973,752
2023F	93,329	83,616	83,662	72,825	74,916	76,228	87,409	87,461	78,147	80,815	85,045	92,172	995,624
After-Savings													
2022S	90,298	80,801	80,856	70,272	72,331	73,624	84,563	84,609	75,489	78,086	82,209	89,168	962,307
2023F	91,368	81,668	81,740	70,935	73,057	74,392	85,584	85,632	76,304	78,952	83,163	90,278	973,073

Note: The commercial class is normalized from 2014 to 2020 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
Before-Savings													
2022S	64,807	54,940	51,149	42,542	37,128	36,250	46,538	46,193	38,848	45,583	55,516	63,082	582,577
2023F	65,192	55,265	51,454	42,796	37,362	36,483	46,834	46,485	39,088	45,858	55,846	63,460	586,125
After-Savings													
2022S	64,456	54,593	50,813	42,220	36,821	35,954	46,246	45,897	38,540	45,261	55,180	62,735	578,717
2023F	64,492	54,573	50,785	42,156	36,752	35,895	46,253	45,897	38,481	45,223	55,184	62,779	578,470

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
Before-Savings													
2022S	49,922	49,087	54,123	51,558	43,838	48,000	48,703	47,580	50,264	47,957	48,513	47,775	587,321
2023F	50,238	49,396	54,438	51,852	44,129	48,312	49,017	47,901	50,575	48,269	48,844	48,099	591,072
After-Savings													
2022S	49,195	48,360	53,402	50,840	43,130	47,296	48,007	46,881	49,566	47,241	47,795	47,067	578,779
2023F	48,797	47,968	53,031	50,464	42,773	46,975	47,708	46,597	49,287	46,956	47,539	46,827	574,920

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
Before-Savings													
2022S	820	759	817	809	839	797	813	829	798	830	782	789	9,682
2023F	820	759	817	809	839	797	813	829	798	830	782	789	9,682
After-Savings													
2022S	804	743	802	795	826	784	801	816	785	816	766	773	9,511
2023F	788	728	788	783	816	775	792	808	777	807	758	765	9,385

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
Before-Savings													
2022S	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
2023F	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
After-Savings													
2022S	691	641	660	2,013	4,935	6,015	8,442	7,956	4,456	2,213	756	693	39,471
2023F	690	640	659	2,011	4,930	6,004	8,425	7,936	4,440	2,204	752	691	39,382

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
Before-Savings														
2022S	725	687	608	516	488	588	658	661	502	537	645	722	783	679
2023F	732	693	614	521	493	593	664	667	506	542	650	728	788	685
After-Savings														
2022S	725	686	608	515	488	587	657	660	501	536	644	721	782	678
2023F	730	692	612	519	491	592	662	665	505	540	649	727	786	684

Note: The peaks shown in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	52	51	43	42	42	42
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.2 CUSTOMER ADDITIONS

Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	912	12,634	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,658	2,679
Commercial	106	1,851	701	613	97	325	280	278	209	429	401	501
Wholesale	-	(1)	-	-	-	-	-	-	-	-	-	-
Industrial	1	8	2	1	-	-	2	(1)	(8)	(1)	-	-
Lighting	(27)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(28)	(30)
Irrigation	17	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-
Total Direct	1,009	14,403	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	3,031	3,150

4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.58	10.19	9.95

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Energy (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	681	788	863	853	905	915	926	932	922	960	962	973
Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
Industrial	291	352	381	380	373	363	403	495	441	472	579	575
Lighting	13	13	16	16	16	16	13	11	11	10	10	9
Irrigation	38	40	40	46	42	42	39	36	37	44	39	39
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak (MW)												
Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021S	2022F
BCH Lardeau	6	6	6	6	6	8	8	7	6	6	7	7
BCH Kingsgate	5	5	5	5	5	5	5	5	5	4	5	5
City of Grand Forks	41	41	39	41	41	39	46	37	38	36	36	36
City of Nelson	80	83	81	83	80	86	88	84	82	86	79	78
City of Penticton	341	348	342	348	345	338	340	338	340	337	351	351
District of Summerland	95	98	94	97	98	98	99	95	99	97	101	101
City of Kelowna	332	94	-	-	-	-	-	-	-	-	-	-
Total	899	675	567	580	574	574	585	566	569	566	579	578

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2017	2018	2019	2020	2021	2022S	2023F
Demand Side Management	(28)	(31)	(26)	(26)	(30)	(28)	(56)

6. VARIANCES TO FORECAST

6.1 *CUSTOMER COUNT VARIANCE*

Customer Count	2016	2017	2018	2019	2020	2021
Actual						
Residential	115,772	117,748	120,291	122,465	124,966	126,678
Commercial	15,073	15,398	15,678	15,956	16,165	16,594
Wholesale	6	6	6	6	6	6
Industrial	50	50	52	51	43	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103
Total	133,550	135,793	138,587	141,027	143,714	145,830
Forecast						
Residential	115,758	116,031	117,774	120,405	124,076	124,603
Commercial	15,042	15,813	16,122	16,405	16,220	16,579
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,082	1,082
Total	133,578	134,585	136,602	139,459	142,865	143,721
Variance (customers)						
Residential	14	1,717	2,517	2,060	890	2,075
Commercial	31	(415)	(444)	(449)	(55)	15
Wholesale	0	0	0	0	0	0
Industrial	1	0	2	0	(14)	(17)
Lighting	(61)	(79)	(77)	(44)	18	14
Irrigation	(13)	(15)	(12)	2	9	21
Total	(28)	1,208	1,986	1,569	849	2,109
Variance (%)						
Residential	0.0%	1.5%	2.1%	1.7%	0.7%	1.6%
Commercial	0.2%	-2.7%	-2.8%	-2.8%	-0.3%	0.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	0.0%	3.8%	0.0%	-32.6%	-40.5%
Lighting	-3.9%	-5.2%	-5.2%	-3.0%	1.3%	1.0%
Irrigation	-1.2%	-1.4%	-1.1%	0.2%	0.8%	1.9%
Total	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2016	2017	2018	2019	2020	2021
Normalized						
Residential	1,296	1,320	1,313	1,266	1,347	1,330
Commercial	905	915	926	932	922	960
Wholesale	574	574	585	566	569	566
Industrial	373	363	403	495	441	472
Lighting	16	16	13	11	11	10
Irrigation	42	42	39	36	37	44
Net	3,206	3,230	3,278	3,306	3,328	3,381
Gross	3,480	3,512	3,564	3,592	3,616	3,677
Forecast						
Residential	1,367	1,353	1,280	1,349	1,326	1,255
Commercial	871	879	912	935	902	952
Wholesale	579	587	586	594	567	584
Industrial	393	407	379	385	453	537
Lighting	13	14	15	13	11	10
Irrigation	39	40	41	42	35	36
Net	3,262	3,282	3,213	3,319	3,294	3,374
Gross	3,540	3,559	3,485	3,602	3,602	3,664
Variance (GWh)						
Residential	(71)	(33)	33	(83)	21	75
Commercial	34	36	14	(3)	20	7
Wholesale	(5)	(13)	(1)	(28)	2	(18)
Industrial	(20)	(44)	24	110	(12)	(64)
Lighting	3	1	(2)	(2)	0	(0)
Irrigation	3	2	(2)	(6)	2	8
Net	(56)	(52)	65	(13)	34	8
Gross	(59)	(47)	79	(10)	14	13
Variance (%)						
Residential	-5.5%	-2.5%	2.5%	-6.6%	1.6%	5.6%
Commercial	3.8%	3.9%	1.5%	-0.4%	2.2%	0.8%
Wholesale	-0.8%	-2.3%	-0.2%	-5.0%	0.4%	-3.1%
Industrial	-5.3%	-12.3%	5.9%	22.2%	-2.7%	-13.6%
Lighting	16.3%	9.4%	-13.4%	-17.8%	2.1%	-2.8%
Irrigation	7.7%	3.9%	-5.2%	-16.7%	5.3%	17.9%
Net	-1.7%	-1.6%	2.0%	-0.4%	1.0%	0.2%
Gross	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	905	915	926	932	922	960	962	973
Wholesale	574	574	585	566	569	566	579	578
Industrial	373	363	403	495	441	472	579	575
Lighting	16	16	13	11	11	10	10	9
Irrigation	42	42	39	36	37	44	39	39
Net	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	274	282	285	287	288	295	299	299
Gross	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak								
Winter Peak (MW)	755	714	682	732	731	685	782	786
Summer Peak (MW)	593	605	631	639	666	653	678	684

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	0%	2%	-1%	-4%	6%	-1%	-2%	0%
Commercial	6%	1%	1%	1%	-1%	4%	0%	1%
Wholesale	-1%	0%	2%	-3%	1%	-1%	2%	0%
Industrial	-2%	-3%	11%	23%	-11%	7%	23%	-1%
Lighting	0%	0%	-17%	-17%	-2%	-11%	-2%	-1%
Irrigation	-9%	0%	-7%	-8%	4%	17%	-10%	0%
Net	1%	1%	1%	1%	1%	2%	3%	0%
Losses & Company Use	1%	3%	1%	0%	1%	2%	1%	0%
Gross	1%	1%	1%	1%	1%	2%	3%	0%
System Peak								
Winter Peak (MW)	10%	-5%	-4%	7%	0%	-6%	14%	0%
Summer Peak (MW)	-3%	2%	4%	1%	4%	-2%	4%	1%

Customer Count	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	50	52	51	43	42	42	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407	1,103	1,103
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103	1,379	1,349
Total Direct	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1%	2%	2%	2%	2%	1%	2%	2%
Commercial	1%	2%	2%	2%	1%	3%	2%	3%
Wholesale	0%	0%	0%	0%	0%	0%	0%	0%
Industrial	0%	0%	4%	-2%	-16%	-2%	0%	0%
Lighting	-2%	-3%	-2%	-1%	-2%	-2%	-22%	0%
Irrigation	0%	-1%	0%	0%	1%	1%	25%	-2%
Total Direct	1%	2%	2%	2%	2%	1%	2%	2%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2019	2020	2021
After- Savings Normalized Actual UPC	10.43	10.89	10.58
Forecast	11.27	10.75	10.10
Variance	(0.84)	0.13	0.49
Variance (%)	-8.0%	1.2%	4.6%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2019	2020	2021
After- Savings Actual Peak	732	725	777
Forecast	764	737	748
Variance	(32)	(12)	29
Variance (%)	-4%	-2%	4%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Energy (MWh)	Peak (MW)	Load Factor
2016	3,480,297	755	0.53
2017	3,511,820	714	0.56
2018	3,563,824	682	0.60
2019	3,592,459	732	0.56
2020	3,615,884	731	0.56
2021	3,676,926	685	0.61
2022S	3,771,436	782	0.55
2023F	3,774,844	786	0.55

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A3

Load Forecast Methods

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1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in Section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year[1]. For the 2023 Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2023 is the Forecast Year (2023F).

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential, wholesale and commercial[3] load classes; therefore these classes are normalized. The irrigation class shows a low R^2 value for the winter, summer and fall seasons; therefore, this class was not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.
[3] The commercial class data is normalized from 2014 to 2021 since a strong correlation was present in those years. All commercial data prior to 2014 is actual because it did not show a correlation to weather at that time.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	39,370	66,140	70,359	64,926
Slope HDD	172	109	-	92
Slope CDD	-	-	245	-
Adjusted R^2	0.72	0.76	0.84	0.77

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	61,401	57,123	58,803	60,135
Slope HDD	58	47	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.91	0.92	0.85	0.91

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	48,156	51,092	49,674	54,643
Slope HDD	24	16	-	(0)
Slope CDD	-	-	78	-
Adjusted R^2	0.58	0.54	0.68	0.53

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,634	5,218	5,079	6,034
Slope HDD	(1)	(11)	-	(10)
Slope CDD	-	-	23	-
Adjusted R^2	0.04	0.76	0.45	0.43

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential, wholesale and commercial classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate

[4] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[5] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2021:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2012-2021) HDD (CDD) as found in Step 2;

   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and

   (d) add the normalization adder to the month's load (residential, commerical or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings[6]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2021) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[6] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2021".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2012 to 2021. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong correlation, it therefore applied a 10-year trend.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2021
R^2	0.84
Adjusted R^2	0.82
df	9
Intercept	414
Slope UPC	-0.20

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-6: Results of Residential Regression

Regression	Residential
Start Year	2019
End Year	2021
R^2	1.00
Adjusted R^2	0.99
df	2
Intercept	(118,476)
Slope Population	0.88

The residential class represented 39.3 percent of the net load in 2021.

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2007 to

2021 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 28.4 percent of the net load in 2021.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2007
End Year	2021
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	123,607
Slope GDP	3
Slope CoK Event	132,847

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers except one. This customer was contacted multiple times but did not respond. Since there was no response, FBC kept their load at 2021 levels. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc. The wholesale class represented 16.7 percent of the net load in 2021.

1.2.4 Industrial

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in. 81 percent of FBC's industrial customers responded to the surveys, accounting for 90 percent of 2021 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group. The industrial class represented 14.0 percent of the net load in 2021.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2021 are included in the forecast but do not overly influence it. The irrigation class represented 1.3 percent of the net load in 2021.

1.2.6 Lighting

The before-savings lighting load uses the 2021 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2021. The lighting class represented 0.3 percent of the net load in 2021.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019-2022 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the 10-year average (2012-2021) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
1.	21	6	Upper Bonnington Old Units Refurbishment Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Complete (Final Report filed in this Annual Review)	Appendix B2
G-165-20 AND G-166-20 – FEI AND FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2.1

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
3.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a
4.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
5.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
7.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Complete	Section 7.2.1
G-42-21 – FBC ANNUAL REVIEW FOR 2020 AND 2021 RATES						
8.	21		COVID-19 Customer Recovery Fund Deferral Account	The Panel approves the following deferral account requests: f. Recording of the COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund deferral account, as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
9.	32	7	Wholesale Customer Load Forecast	The Panel directs FBC to provide details of any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts.	Complete	Section 3.4.3
10.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Section 6.3.4

Appendix B2

FortisBC Inc.

Upper Bonnington Old Units Refurbishment Project

Final Report

August 2022

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1. PROJECT STATUS

1.1 *PROJECT BACKGROUND*

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Upper Bonnington (UBO) Old Units Refurbishment (UBO Refurbishment Project, or the Project) in Order G-8-17. Directive 6 of Order G-8-17 required FBC to file specific information on the Project's updated scope, progress and costs as part of FBC's future annual review applications. Specifically, the BCUC directed FBC to provide the following information about the progress of the Project:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the Project timeline provided in the [Annual Review for 2017 Rates] Application to any updated Project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or Project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involved the refurbishment of generating Units 1-4 (the Old Units), which are over 100 years old, in order to extend their lives for an additional 20 years or more. The Project also reduced the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following final report regarding the UBO Refurbishment Project in compliance with Directive 6 of Order G-8-17, including final Project costs (Final Report).

The Project scope of work was completed and closed out in Q4 2021. The four generating units and associated equipment have been put into commercial operation and are performing well.

The Project successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant.

[1] Order G-8-17, Appendix A, page 21.

With regard to the major environmental and safety accomplishments achieved during Project execution, FBC reports that it followed the Environmental Management Plan (EMP) developed in 2017 and the Project had no reportable environmental incidents. Further, the Project accumulated approximately 160 thousand hours without a lost time incident. The majority of the effort on the Project was internal FBC labour, with approximately 19 thousand hours supplied externally. While the COVID-19 pandemic presented challenges during the second half of the Project, the policies and procedures implemented by FBC minimized the risk of infection and Project interruption.

1.2 *WORK COMPLETED SINCE AUGUST 2021 STATUS REPORT*

The following is a brief summary of the work completed since the August 2021 status report filed as Appendix B2 to FBC's Annual Review for 2022 Rates application.

Balance of Plant

The scope of the balance of plant work evolved as the Project progressed and included the following:

Floor modifications – As equipment was removed, the concrete bases were demolished and floor repairs were completed. The plant floor loadings, drawings, demarcation, procedures and site signage updates were completed.

Ventilation access walkway – With the removal of the old switchgear concrete structure, both wall and floor repairs were required. The switchgear concrete structure provided access to plant ventilation systems; with the removal of this concrete, new access walkways and ladders were designed and installed.

Water wheel excitation decommissioning – The water wheel exciters and associated equipment were removed and the intakes were plugged with concrete. The holes through the generator and turbine floors were capped with steel plates. The exciter rheostats and buss were removed and the rheostat room was repurposed for plant equipment storage.

Units 2 and 3

Minor work was completed on Units 2 and 3 which was intentionally delayed until site conditions were preferable in 2021. The work included painting, hazardous materials removal, and the rotor oil leak repair on Unit 3.

Project Close

The Project was closed in Q4 2021 with all equipment and plant transferred back to generation operations.

2. PROJECT SCHEDULE

The following table is updated to show the final completion dates for each unit as well as the balance of plant work.

Table B2-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	Q4, 2017	Q4, 2017	Complete
All Units Detailed Engineering	Q1, 2018	Q1, 2018	Complete
Balance of Plant Engineering	Q3, 2020	Q4, 2020	Complete
Procurement of All Major Mechanical/Electrical	Q2, 2020	Q2, 2020	Complete
Construction			
Refurbishment of Unit 3	Q4, 2017	Q4, 2017	Complete
Refurbishment of Unit 4	Q4, 2018	Q4, 2018	Complete
Refurbishment of Unit 1[1]	Q4, 2020	Q4, 2019	Complete
Refurbishment of Unit 2[1]	Q4, 2019	Q4, 2020	Complete
U3 Oil Leak Deficiency Repair	Q1, 2021	Q2, 2021	Complete
Balance of Plant Work	Q2, 2021	Q3, 2021	Complete
Closeout	Q3, 2021	Q4, 2021	Complete

Note:

[1] *Units 1 and 2 construction years were changed from the original schedule to gain efficiencies by removing equipment while operating a live plant.*

2.1 *SCHEDULE SUMMARY*

The rotor oil leak repair work on Unit 3 delayed portions of the Balance of Plant scope of work from Q2 2021 to Q3 2021. The work completed on Units 2 and 3 as outlined above in Section 1.2 was completed in parallel with the Balance of Plant work, and the Project was closed in Q4 2021.

While some of the work was re-scheduled around sequencing concerns and operational constraints, the overall Project duration was as originally planned.

3. PROJECT COSTS

The following table outlines the final Project expenditures.

Table B2-2: Cost Summary

Description	Application/ Control Budget	Final Costs	Variance	Variance
	($000s)			(%)
Unit 4	6,634	8,058	1,424	21%
Unit 3	4,079	6,529	2,450	60%
Unit 2	5,641	6,606	965	17%
Unit 1	8,050	8,287	237	3%
Balance of Plant	860	1,657	797	93%
Subtotal - Construction	25,264	31,137	5,873	23%
Cost of Removal	1,880	1,840	-40	-2%
Project Contingency	3,771	-	-3,771	-
Subtotal - Construction & Removal	30,916	32,997	2,062	7%
AFUDC	867	1,174	307	35%
Total Project Cost	31,783	34,151	2,369	7%

3.1 *PROJECT COST SUMMARY*

The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). The Project's cost estimate was at an AACE Class 4 estimate class because of the difficulty in defining the full scope without dismantling the units. Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry. As reported in the August 2020 status report, this approximately $2.4 million variance resulted primarily from higher than planned costs to rewind the generators and to refurbish the concealed turbine components.

The cost variances in each Project category are further described below.

Units 1-4 – These variances are explained in the August 2020 status report. In 2021, both Units 2 and 3 painting scope of work that had been delayed was completed. Unit 3 rotor oil leak repair work was completed for a final cost of approximately $0.252 million. These completed scopes are included in the final costs presented in Table B2-2.

Balance of Plant Work – The balance of plant work scope of work was completed with an unfavourable variance of $0.797 million. The Balance of Plant scope of work evolved as the

Project progressed. The installation of new equipment and removal of old equipment within an operating facility presented unanticipated challenges that were not able to be defined during the planning stage. This variance is primarily due to the extra effort required to remove equipment and cabling which was not expected to contain asbestos and the additional civil structural scopes, as well as the floor modifications required to facilitate the new plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.840 million, which represents a favourable variance of $0.040 million.

Contingency – Project contingency has been utilized to offset the variances that were encountered among the different Units.

AFUDC – The total cost for AFUDC is $1.174 million, which represents an unfavourable variance of $0.307 million due to the higher overall Project costs.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout the Project, FBC made adjustments to address unforeseen challenges and issues which were either not considered or not accessible during the planning stage. These adjustments totalled approximately $2.015 million and were explained in the August 2020 status report.

4. CONCLUSION

The UBO Refurbishment Project is complete and has successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant. The Project maintained schedule and returned the Units to commercial service within the year planned. The final Project costs were well within the typical accuracy range of an AACE Class 4 cost estimate and totalled $34.151 million. This approximately $2.4 million increase was required to complete scope and ensure the units could operate safely for 20 years or more, as originally planned.

Appendix C
PROJECTS AND MARKET REPORT

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

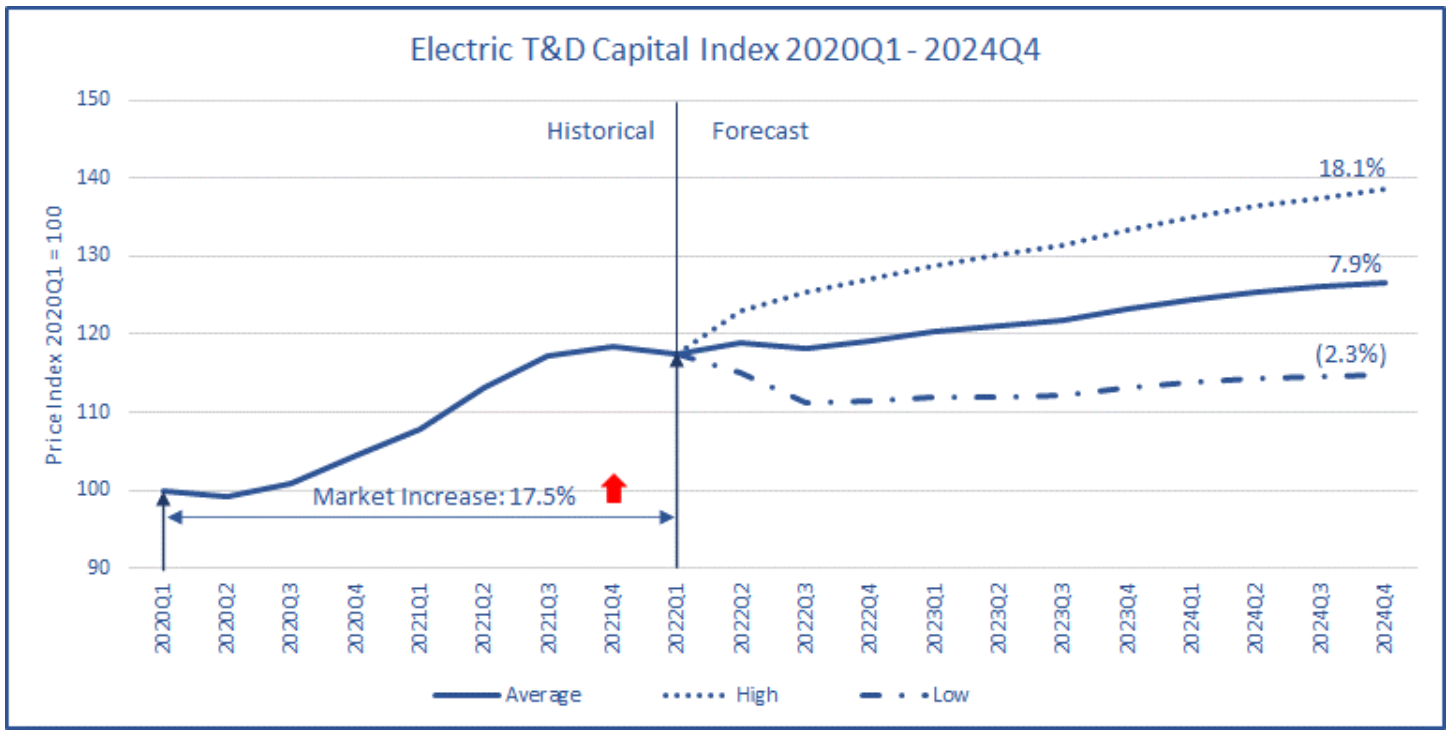
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

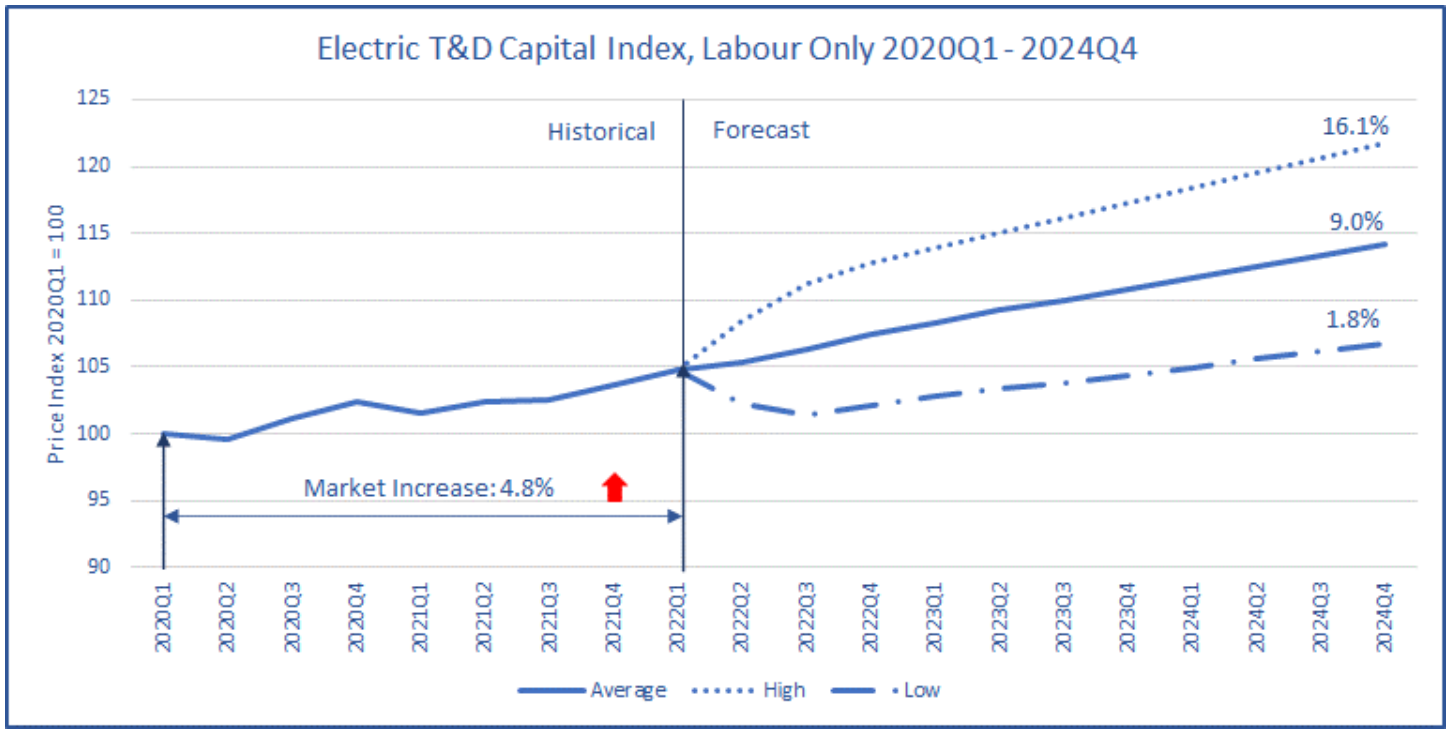
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

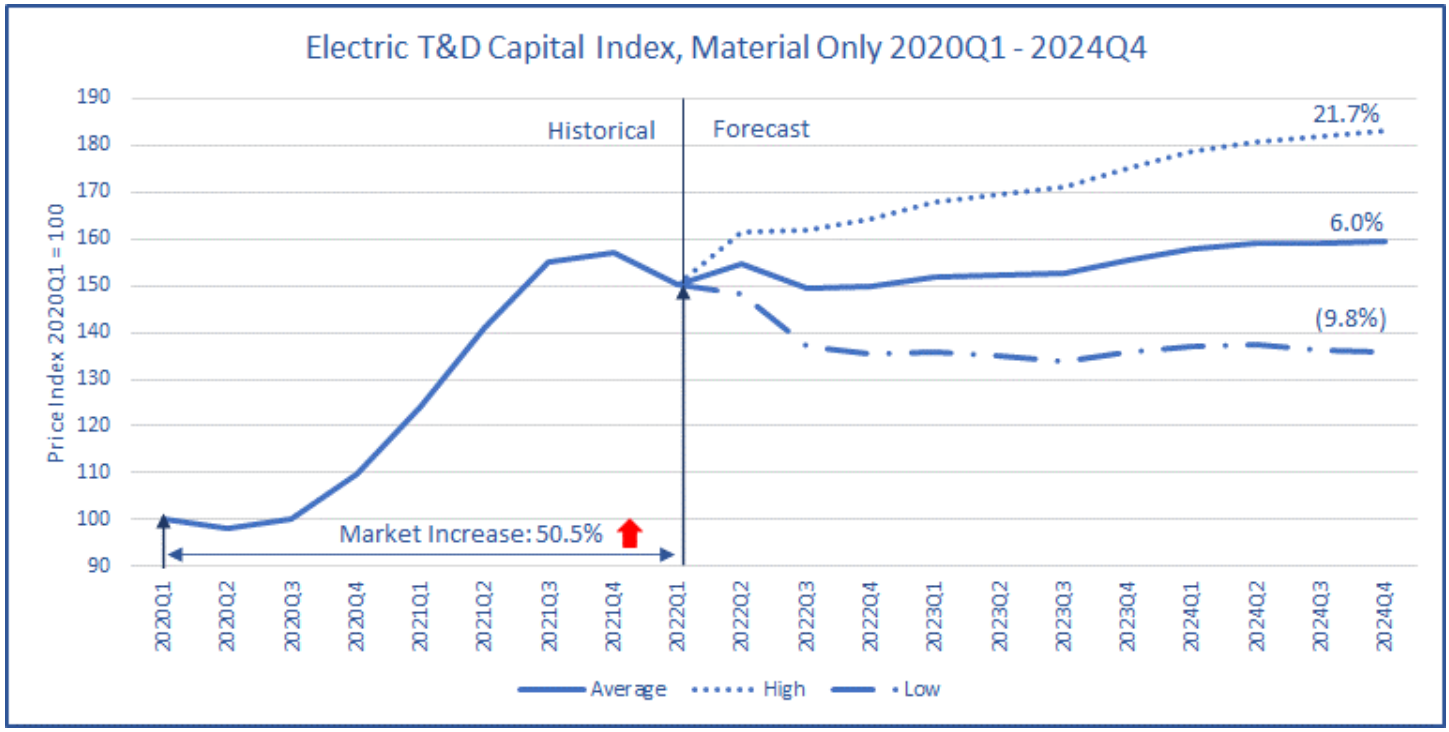
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



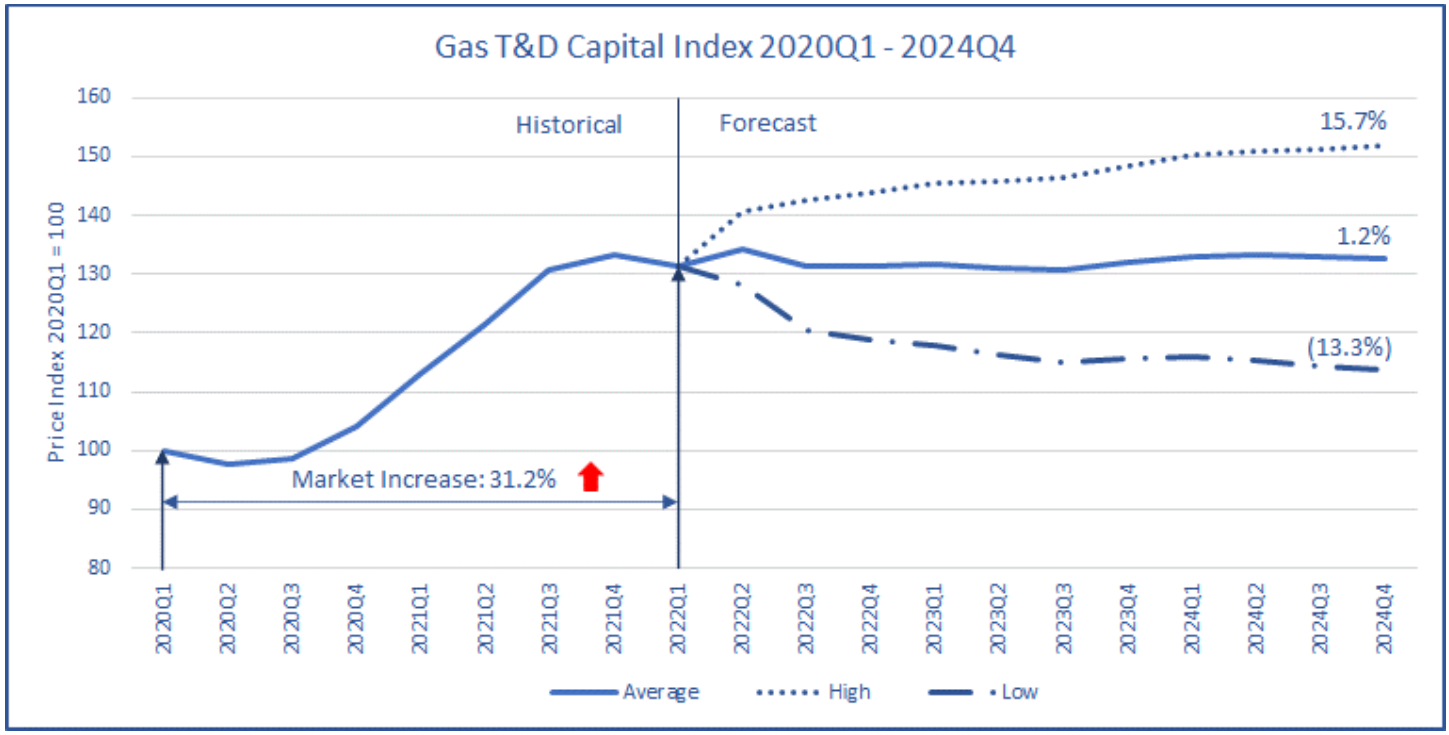
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

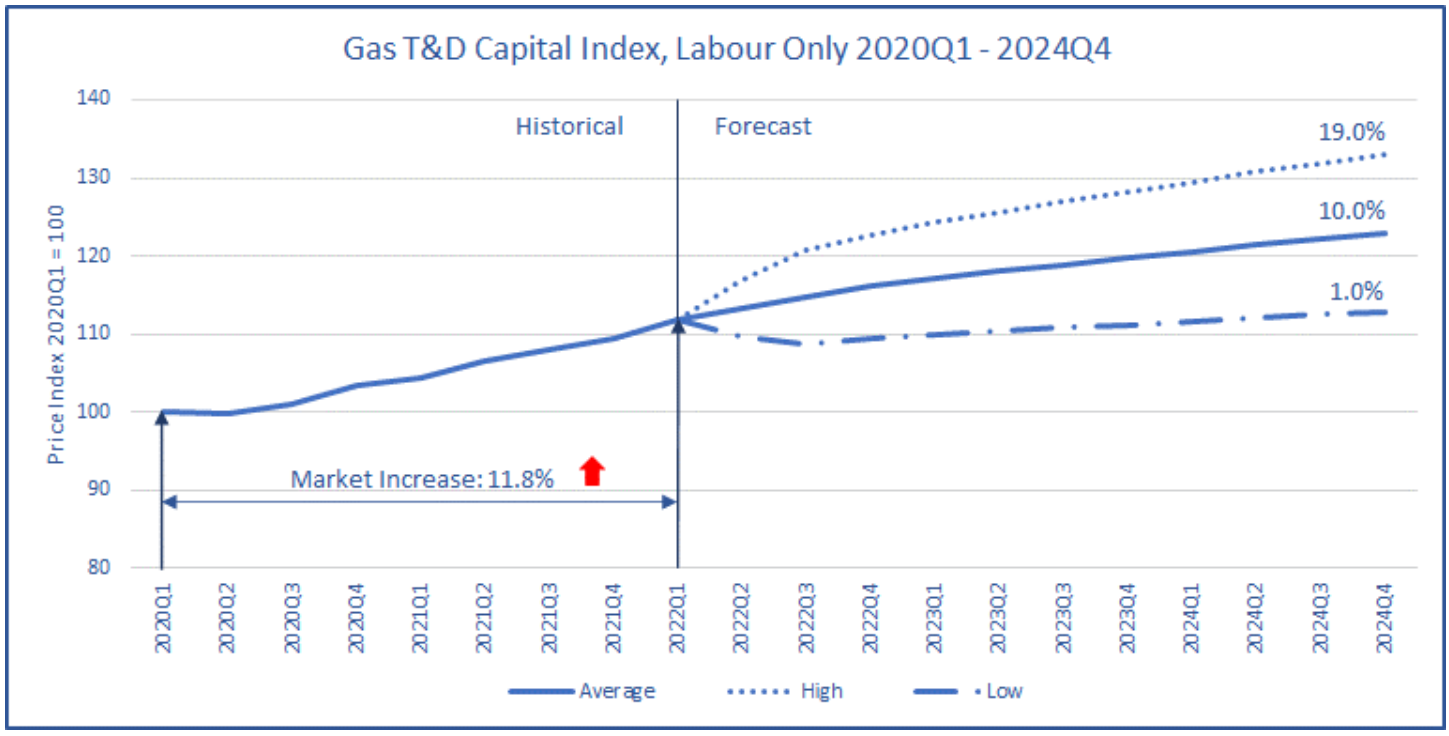
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

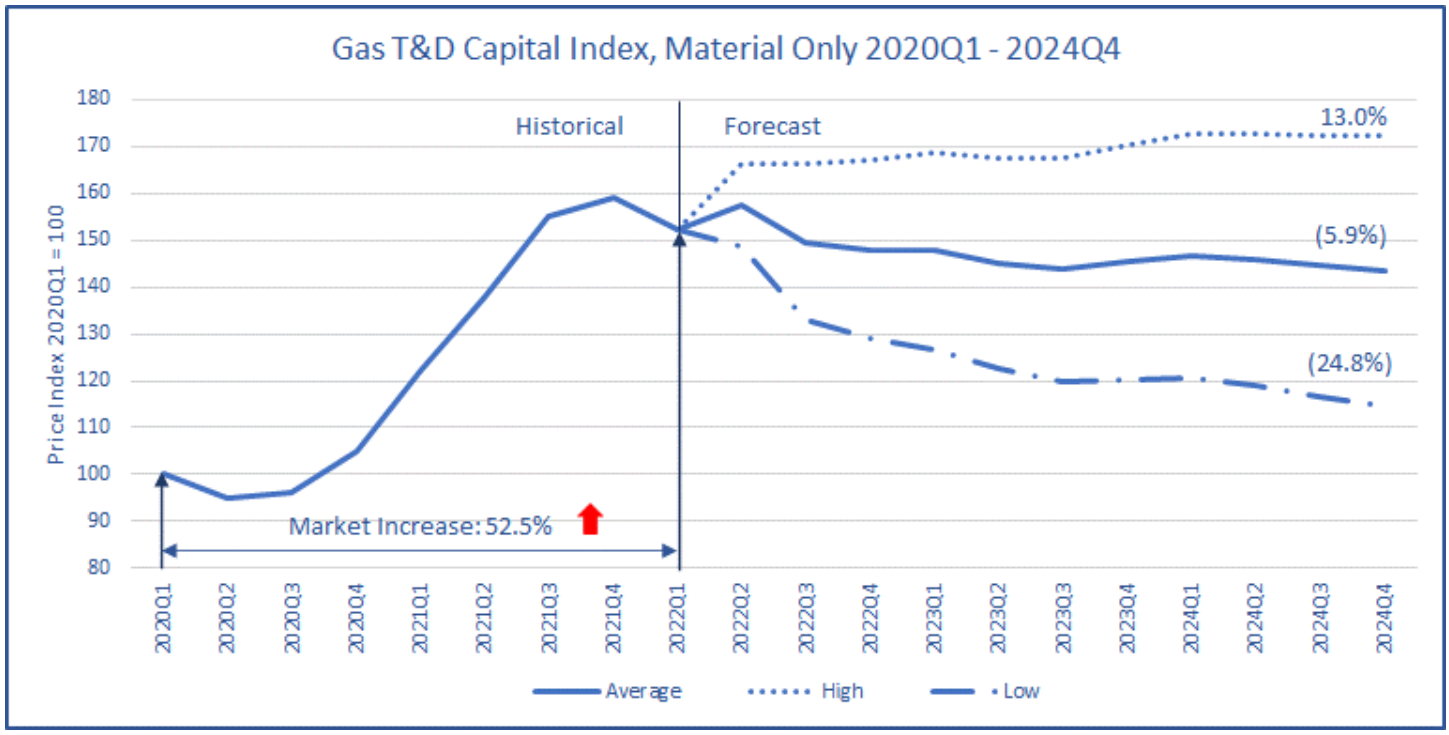
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

Appendix C2

Project Descriptions for Forecast Growth and Sustainment Capital

August 2022

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1. INTRODUCTION

In this appendix, FBC provides descriptions of growth and sustainment capital projects over $1 million.

As described in Section 7 of the Application, FBC's growth capital is divided into the following portfolios:

1. Transmision Growth;
2. Distribution Growth; and
3. New Connects.

FBC's sustainment capital is divided into the following portfolios:

1. Generation;
2. Transmission Sustainment;
3. Stations Sustainment;
4. Distribution Sustainment; and
5. Telecommunications.

The projects over $1 million in each of these categories are described below.

2. GROWTH CAPITAL

2.1 *TRANSMISSION GROWTH*

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load for adequate supply during periods of peak demand and adverse weather conditions.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[1]

[1] MRP Application, Section 3.4.1.1.1, Table C3-23, pp. C-82 and C-83.

Table C2-1: FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	4,633	-	-	-	-
Summerland Transformer Replacement	539	2,063	-	-	-
Beaver Park Substation Upgrade	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	-	-	-	-	1,086

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-2: Updated FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	5,311	66	-	-	-
Beaver Park Substation Upgrade	-	636	4,936	6,223	-
Duck Lake 2nd Transformer Addition	-	-	-	-	1,088

Each of these projects is described further below.

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer was forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer was installed and put into service at the Sexsmith substation in 2020. The actual costs of this project were approximately $5.3 million with the bulk of capital expenditures occurring in 2020.

- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to anticipated new commercial development in Summerland, peak load at this wholesale delivery point was previously forecast to exceed 95 percent of the contract demand limit during the MRP term. Since the most recent load forecast projects that peak load will not exceed this threshold until 2026, no project expenditures are planned during the MRP term. FBC will continue to engage with the District of Summerland municipal utility to discuss options to increase wholesale capacity. This project is thus not included in Table C2-2.

- **Beaver Park Substation Upgrade:** This project is driven by load growth in the Trail area and equipment condition issues as the BEP T1 transformer tap changer cannot be adequately maintained. The project seeks to rebuild the Beaver Park substation on an expanded station footprint. To meet planning criteria and continue to provide a reliable supply, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is approximately $11.8

million. The total project costs have increased since the MRP Application filing in 2019 due to several factors, including archaeological requirements and increases in engineering, materials and construction costs. Commodity cost increases have placed significant pressure on materials.

- **Duck Lake Second Transformer Addition:** This project is driven by significant development occurring in the area served by the Duck Lake substation. FBC planning studies indicate that a second distribution transformer is required at Duck Lake to maintain the current level of reliability and support distribution contingency planning criteria. As the pace and scale of development has exceeded what was anticipated when the MRP Application was filed, this project has now been advanced ahead of the DG Bell project described below. The estimated cost of this project is $5.3 million; however, the cost could increase further as a result of potential commodity cost increases impacting the cost of materials.
- **DG Bell Second Transformer Addition:** FBC planning studies indicate that a second distribution transformer is required at DG Bell to maintain the current level of reliability and support distribution contingency planning criteria. This project has been deferred from the original 2024-25 construction schedule to accommodate the Duck Lake Second Transformer Addition. This project is now planned for 2025-26 with an estimated in-service date of 2026. This project is thus not included in Table C2-2.

2.2 *DISTRIBUTION GROWTH*

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[2]

Table C2-3: FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	1,970	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

[2] MRP Application, Section 3.4.1.1.2, Table C3-24, pp. C-83 and C-84.

Table C2-4: Updated FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	-	26	1,870	-	-
Huth CoP 13KV Supply	1,219	62	-	-	-

Each of these projects is described further below.

- **DG Bell Feeder 4 Addition:** This project was deferred due to the timing of City of Kelowna road construction from 2020 to 2022; however, the total actual project cost is lower than forecast in the MRP Application.
- **Huth CoP 13KV Supply:** This project was added in 2020. The project was required to ensure that FBC continues to meet the terms of its Wholesale Agreement with the City of Penticton at the Huth substation Point of Delivery.

2.3 *NEW CONNECTS*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3. SUSTAINMENT CAPITAL

3.1 *GENERATION SUSTAINMENT*

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC's Generation capital is grouped into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	685	821	979	1,128	1,019
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,467	1,396	-	-	-

[3] MRP Application, Section 3.4.1.2.1, pp. C-84 to C-88.

	Category	2020	2021	2022	2023	2024
Other Gates Upgrades	Hydraulic Dam Structures	481	100	414	241	545
Dam Safety Instrumentation	Hydraulic Dam Structures	715	765	-	-	806
Guarding of Rotating Parts	Hydraulic Dam Structures	194	324	458	295	287
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	35	582	2,035	-
Generator Excitation System and Control Systems	Generating Equipment	-	67	556	556	-
Generator Thrust Bearing Cooling System	Generating Equipment	247	271	295	198	198
Dewatering and Drainage Systems	Generation Auxiliary Equipment	116	349	349	349	349
Station Service Upgrade	Generation Auxiliary Equipment	333	495	286	286	300
COR Annex Building Replacement	Buildings and Structures	-	-	-	198	1,606

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-6: Updated FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	715	745	1,128	651	1,061
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,436	2,893	-	-	-
Dam Safety Instrumentation	Hydraulic Dam Structures	896	287	1,059	100	100
Rehabilitation of Dam Stability Anchors	Hydraulic Dam Structures	78	442	392	326	-
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	22	501	1,395	2,085
Generator Excitation System and Control Systems	Generating Equipment	-	271	344	485	836
Dewatering and Drainage Systems	Generation Auxiliary Equipment	126	217	655	1,166	222

	Category	2020	2021	2022	2023	2024
Station Service Upgrade	Generation Auxiliary Equipment	298	577	834	512	260
COR Annex Building Replacement	Buildings and Structures	4	4	186	200	1,606

Each of these projects is described in further detail below:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 to address requirements of the BC Dam Safety Regulation and deterioration of concrete structures. The cost for this project is $0.332 million lower than forecast in the MRP Application due mainly to reduced scope at the Lower Bonnington Dam as safety issues are restricting access to lower areas of the construction scaffold in the tailrace during unit start-up. FBC is working on designing a solution to this issue.
- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project was completed in 2021 at a higher cost than forecast due to complexities encountered during construction and the implementation of a monorail system for the installation of stoplogs that was not considered initially.
- **Other Gates Upgrade Project:** This project is now forecast to cost less than $1 million due to FBC implementing a simpler solution for strengthening the LBO intake superstructure. This project is thus not included in Table C2-6.
- **Dam Safety Instrumentation Project:** This project addresses the requirement in section 19(1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. FBC has thus far completed the installation of dam safety instrumentation at LBO and UBO and will complete the installation of dam safety instrumentation at South Slocan (SLC) in 2022. The higher costs are primarily due to higher drilling costs. The installation of the dam safety instrumentation at Corra Linn (COR) has been delayed with only the engineering being planned to occur in 2023-2024.
- **Guarding of Rotating Parts Project:** This project is now forecast to cost less than $1 million due to a reduction in scope. The original forecast included installing guards on spillway and intake gates, but during detail design, more effective administrative and operational methods were developed and implemented which have resulted in cost reductions. This project is thus not included in Table C2-6.
- **Rehabilitation of Dam Stability Anchors:** This project was included in the Other Hydraulic Dam Structures Projects category in the MRP Application, as at the time of filing it was expected to cost less than $1 million. However, the scope of work has increased from $0.302 million to $1.238 million due to damage to the anchors' heads being more extensive and the number of anchor heads that required repairs being higher than initially anticipated; the degree of the anchor head damage could only be established while

inspecting the anchors which are located on the overflow spillway. The rehabilitation of the LBO dam stability anchors will be competed in 2022. Rehabilitation of the COR dam stability anchors will commence in 2023 and will complete in 2025.

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. Work on this project was accelerated to mitigate the anticipated delays in the global supply chain due to the COVID-19 pandemic. The estimated cost of this project is approximately $1.445 million higher than originally forecast due to the costs of the runner being higher. The expected in-service date is December 2024.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 with Unit 6 at UBO. The updated cost of this project is approximately $0.765 million higher due mainly to higher costs with the procurement of the control and excitation systems.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project is now forecast to cost less than $1 million as FBC has implemented a better designed solution that has resulted in cost savings. This project is thus not included in Table C2-6.
- **Dewatering and Drainage Systems Rehabilitation Project:** This project was budgeted based on costs including rehabilitation of pipes valves and other components of the dewatering and drainage systems. During detail design it was discovered that this solution was not feasible and a new solution was designed and is being implemented which is based on a pump in gate design that has an increased cost of $0.690 million. The first system is planned to be put in service at SLC in 2023 and engineering for the next plant will occur in 2024.
- **Station Service Upgrade Project:** This project includes upgrading the protection system of FBC's station service system and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements. The estimated cost of this project is $0.186 million higher due to the need to address deficiencies related to LBO powerhouse grounding and bonding issues that were uncovered while doing investigations in 2021.
- **Corra Linn Annex Building Replacement Project:** FBC has decided to start the preliminary engineering in 2022 and is planning to complete the project in 2024.

3.2 *TRANSMISSION SUSTAINMENT*

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[4].

Table C2-7: FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,100	-	-	-	-
30, 32, 19 Lines Right of Way	647	651	658	656	652

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-8: Updated FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,087	91	-	-	-
30, 32, 19 Lines Right of Way	458	637	652	652	648

Each of these projects is described in further detail below:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project included expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment, including stubbing poles and replacing poles and cross-arms. The project was completed as planned in 2020.
- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring an additional right of way predominantly upslope of the existing right of way for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages. These projects are in progress, with FBC implementing land owner agreements to widen the right of way.

3.3 *STATIONS SUSTAINMENT*

FBC's substation sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks.

[4] MRP Application, Section 3.4.1.2.2, pp. C-89 and C-90.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[5]

Table C2-9: FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
AS Mawdsley Tranformer Replacement	-	-	-	-	3,802
Trout Creek Transformer Replacement	2,263	-	-	-	-
Kaleden Transformer Replacement	-	-	-	-	2,716
Salmo Station Upgrade	3,718	7,154	-	-	-
Fruitvale Station Upgrade	-	-	-	-	3,802

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-10: Updated FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Trout Creek Transformer Replacement	153	2,660	1,568	-	-
Keremeos 2nd Transformer Addition	-	-	-	543	2,700
Salmo Station Upgrade	4,778	5,143	-	-	-
Fruitvale Station Upgrade	-	-	-	1,087	7,021

Each of these projects is described in further detail below:

- **AS Mawdsley Transformer Replacement:** FBC is now planning to file a Certificate of Public Convenience and Necessity (CPCN) application for this project as the cost is forecast to be above the $20 million materiality threshold. This project is thus not included in Table C2-10.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition, as the transformer is 52 years old and uses the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546). The acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicated a cracked LTC terminal board. The project is currently in execution with an estimated in-service date of 2022. Increases in project costs are due to delays related to the lands purchase and ALR approval, along with significant additional work related to other end of life station equipment. Further

[5] MRP Application, 3.4.1.2.3, Tables C3-34 and C3-35, pp. C-91 to C-93.

investigation of the station after the MRP proceeding revealed that the entire station was in a similar condition as the transformer which resulted in a rebuild of the station.

- **Keremeos Second Transormer Addition:** This project is driven by asset condition. The Keremeos transformer has a 48 year old LTC that is not functioning. Based on the resulting operational challenges with the control of customer voltages, this transformer replacement is a high priority.
- **Kaleden Transformer Replacement:** This project has been deferred until after the end of the MRP term to accommodate the previously unforeseen Keremeos Transformer Replacement project. The existing Keremeos transformer presents a larger risk at this time, but planning remains underway for replacement of the Kaleden transformer in 2025-26. This project is thus not included in Table C2-10.
- **Salmo Station Upgrade:** This project was driven by equipment condition issues and aging infrastructure at the Salmo and Ymir substations. The project rebuilt the Salmo substation on the existing station footprint and decommissioned the Ymir substation. The Ymir substation customers were permanently transferred to the Salmo substation. Construction began in 2020 and was completed in 2021. The total cost of this project was $9.9 million. The overall total project cost was less than forecast due primarily to lower actual costs for the distribution and transmission line work. The replacement of the Salmo Station 13 kV Switchgear was also included in this project.
- **Fruitvale Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure at the Fruitvale and Hearns substations. The Hearns single phase transformer units are approximately 72 years old, and the Fruitvale metal-clad switchgear is approximately 55 years old; this equipment is at risk of failing. The project seeks to rebuild and relocate the Fruitvale substation, while decommissioning the Hearns substation. The Hearns substation customers would be permanently transferred to the Fruitvale substation. The existing Fruitvale substation footprint is too small to accommodate the rebuild, and land will need to be acquired for the upgrade. To meet planning criteria and continue to provide a reliable supply to the Fruitvale area, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is $12.5 million. FBC forecasts spending $1.1 million in 2023, $7.0 million in 2024, and $4.4 million in 2025 with an estimated in-service date of 2025. The total project costs have increased since the MRP Application due to several factors, including land acquisition requirements and increases in engineering, material and construction costs.

3.4 *DISTRIBUTION SUSTAINMENT*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3.5 TELECOMMUNICATIONS SUSTAINMENT

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[6].

Table C2-11: FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	937	953	-
SCADA System Replacement	Systems Upgrades and Replacements	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	548	875	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-12: Updated FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	-	841	853
SCADA System Replacement	Systems Upgrades and Replacements	-	-	-	543	1,080
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	-	-	540

Each of these projects is described in further detail below:

- **Backbone Transport Technology Migration:** This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. The project, which was originally forecast to start in 2022, is now expected to commence in 2023.
- **SCADA System Replacement Project:** This project was planned to start in 2021; however, due to limited resources the business analysis was not initiated until late 2021,

[6] MRP Application, Section 3.4.1.2.5, pp. C-99 to C-101.

resulting in delays to determine the best SCADA solution. The estimated cost of this project has decreased to approximately $6 million.

- **VHF Radio System Replacement Project:** The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice. In 2024, the first stages of the VHF radio replacement project are expected to start, with the project continuing into 2025.

Appendix D
DRAFT ORDER

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2023 Rates

BEFORE:
E. B. Lockhart, Panel Chair
C. M. Brewer, Commissioner
A. Pape-Salmon, Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-166-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Inc. (FBC). In accordance with the 2020-2024 MRP Decision, FBC is to conduct an annual review (Annual Review) process to set its rates for each year;

B. By letter dated June 28, 2022, FBC proposed a regulatory timetable for the Annual Review of its 2023 rates;

C. By Order G-193-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FBC's 2023 rates, which included FBC filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FBC's responses to undertakings at the workshop, and written final and reply arguments;

D. On August 5, 2022, FBC submitted its materials for the Annual Review for 2023 Rates Application (Application). In the Application, FBC requests a 3.99 percent rate increase over 2022 rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determination.

NOW THEREFORE pursuant to sections 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FBC is approved to:

    a. Create a rate base deferral account for the 2023 Joint Pole Use Audit and amortize the deferral account over five years commencing January 1, 2023; and

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023.

4. FBC is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. Directive 6 of Order 42-21 is varied as follows: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

6. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

7. FBC is directed to file with the BCUC as a compliance filing, within 15 days of the issuance of this order, amended tariff pages and finalized financial schedules for 2023, in accordance with the terms of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Diane Roy
Vice President, Regulatory Affairs

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September 25, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Project No. 1598967

Annual Review for 2019 Rates (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On August 10, 2018, FBC filed the Application referenced above. In accordance with Commission Order G-142-18 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. EVALUATION OF THE PERFORMANCE BASED RATEMAKING (PBR) PLAN

1.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.1, p. 5; FBC Annual Review for 2018 Rates (FBC 2018 Annual Review), Exhibit B-3, BCUC IR 2.1, Table 1-2

O&M savings

On page 5 of the Fortis BC Inc. (FBC) Annual Review for 2019 Rates Application (Application), FBC states that it is projecting 2018 Operating & Maintenance (O&M) expenses, excluding items forecast outside of the PBR formula, to be approximately $1.0 million lower than the formula amount. Embedded Productivity Improvement Factor (PIF) savings for 2018 are $0.6 million as shown in Table 1-2:

Table 1-2: Formula O&M Savings 2014 to 2018 ($ millions)

	Actual	Formula	Variance	1.03% PIF
2014	$ 52.0	$ 52.7	$ 0.7	$ 0.5
2015	51.9	53.0	1.1	0.5
2016	51.8	53.6	1.8	0.6
2017	52.5	54.1	1.6	0.6
* 2018	53.8	54.8	1.0	0.6
Cumulative Savings			$ 6.1	$ 2.8

Further, FBC states on page 5 of the Application that it "continues to be faced with the challenge of finding new productivity opportunities to meet the annual savings embedded in the formula, and to sustain the level of incremental O&M savings achieved in recent years… Contributing also to the productivity challenge are new cost pressures the Company is facing."

1.1 Please confirm, or explain otherwise, that amounts shown as "1.03% PIF" savings in Table 1-2 above are in addition to amounts shown as "Variance" savings in the table.

Response:

Confirmed.

The savings shown under "Variance" result from the difference between actual O&M expenditures and formula allowed O&M. The savings under "1.03% PIF" are the embedded Productivity Improvement Factor (PIF) savings.

1.2 Please provide a breakdown of the projected 2018 O&M savings between one-time and sustainable savings as it relates to the $1.0 million formula savings and $0.6 million PIF savings.

Response:

FBC provides the following discussion of the formula and Productivity Improvement Factor (PIF) related O&M savings to enhance clarity and interpretation of the information. Formula savings are calculated by taking the difference between the actual O&M spending and the allowed O&M as provided using the formula approach (i.e. inflation, growth and productivity). Any savings calculated may be considered as one-time or permanent (sustainable), depending on the nature of the variance (i.e., temporary vacancy savings are considered one-time savings whereas a permanent headcount reduction would be considered permanent savings). On the other hand, the PIF-related savings are determined based on the approved PIF factor (1.03%) applied to the O&M Base. The PIF-related savings are imbedded as part of the formula and reduce the O&M Base funding by approximately $0.6 million each year. However, the savings cannot clearly be identified as permanent, as permanent savings are typically determined by comparing actual O&M spending to the allowed O&M funding available, instead of by reducing broadly the allowed funding available as the PIF does.

Formula savings can decrease as a result of cost pressures that increase actual spending compared to the allowed funding. Additionally, the impact of the PIF reduces the O&M Base funding that would otherwise be available. Without sufficient productivity related savings to offset the decreased allowed funding resulting from the annual PIF challenge, all else equal, the resulting formula savings will be lower.

For 2018, the $0.6 million PIF savings are included in the allowed formula O&M and FBC is expecting additional formula savings (i.e. actual spending lower than the formula allowed funding). As discussed earlier, the PIF related savings cannot clearly be identified as permanent.

For the projected 2018 formula O&M savings of approximately $1.0 million, $0.4 million is considered sustainable with the remaining $0.6 million considered one-time. As indicated in the response to BCUC IR 1.1.2 in the 2018 FBC Annual Review, sustainable formula O&M savings include $0.3 million for the sharing of Gas and Electric Call Centre staff and $0.3 million of savings due to the Company's broad-based productivity focus (i.e., smaller scale improvements). In addition to the ongoing impact of the PIF and the increasingly difficult challenge of finding new productivity opportunities, cost pressures in 2018 reduce the projected sustainable formula O&M savings. These cost pressures are approximately $0.1 million required for staffing to support the Customer Service Systems group and approximately $0.1 million for cyber security costs which was discussed as part of the 2018 FBC Annual Review Application, Section 1.4.1, page 4.

The remaining projected $0.6 million of formula O&M savings (i.e., $1.0 million total formula O&M savings less $0.4 million permanent savings) are considered one time in nature and consist of labour savings and timing of expenditures which naturally fluctuate from year to year.

1.3 Please explain why FBC finds it challenging to sustain the level of incremental O&M savings achieved in recent years. As part of this response, please specifically identify the types of O&M savings achieved during the PBR term which FBC does not consider sustainable going forward and why these savings are not sustainable.

Response:

FBC clarifies the reference to "the level of incremental O&M savings achieved" is to formula O&M savings. The challenge of maintaining the level of formula O&M savings achieved in recent years is not necessarily due to the formula O&M savings achieved in recent years not being sustainable. Instead, it is due to the ongoing impact of the PIF factor, the increasingly difficult challenge of finding new productivity opportunities and cost pressures the Company is experiencing. Considering the increasingly difficult challenge of finding new productivity opportunities with significant incremental savings, the ongoing impact of the PIF factor itself reduces the allowed O&M funding each year by approximately $0.6 million.

Without sufficient productivity related savings to offset the decreased allowed funding as a result of the annual PIF challenge, all else equal, formula savings will be lower. The PIF influence coupled with the cost pressures discussed in the response to BCUC IR 1.1.2 are expected to contribute to the forecasted decline in annual formula savings.

To offset some of these cost pressures, FBC has been continuing its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling of vacancies and pursuing initiatives that result in savings that are shared with customers while maintaining service levels.

1.4 Please explain what new cost pressures FBC is experiencing, including why they are considered new pressures for 2018 and beyond.

Response:

Please refer to the response to BCUC IR 1.1.2.

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 2.1 in the 2018 Annual Review, FBC stated:

> For 2017, FBC estimates that approximately $0.6 million of the $1.2 million [formula] O&M savings are one-time in nature. The remaining $0.6 million of projected sustainable savings consists of approximately $0.3 million from the sharing of Gas and Electric Contact Centre staff and $0.3 million of savings due to the Company's broad-based productivity focus…

On page 5 of the Application, Table 1-2 shows actual 2017 formula O&M savings were $1.6 million.

1.5 Please explain in detail the causes/factors which resulted in actual 2017 formula O&M savings being $0.4 million higher than what was projected in the FBC 2018 Annual Review application.

Response:

The approximate $0.4 million higher 2017 formula O&M savings than projected in the FBC 2018 Annual Review were primarily the result of labour savings due to vacancies and delayed hires and timing of expenditures in the Environmental Health and Safety and Human Resources departments. Several positions remained vacant longer than anticipated when the Application was filed mid year 2017. Lower non-labour expenditures also contributed to the savings observed.

1.6 Please provide a breakdown of actual 2017 formula O&M savings between one-time and sustainable savings.

Response:

Please refer to the response to BCUC IR 1.1.2.

2.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 5;

FBC 2018 Annual Review, Exhibit B-3, BCUC IR 4.1

Sharing of gas and electric contact centre staff

In response to BCUC IR 4.1 in the 2018 Annual Review, FBC explained the method for allocating costs between FBC and FortisBC Energy Inc. (FEI) for shared personal, stating:

> FBC and FEI are charging (allocating) costs between each other for shared personnel consistent with the requirements of the FEI All-inclusive Code of Conduct and Transfer Pricing Policy. Where the costs can be directly assigned, the costs of the shared personnel are charged based on timesheets and fully loaded hourly rates (i.e., including time off and benefits). Where the costs cannot be directly assigned, FBC and FEI use a cost driver approach as a fair and reasonable way to allocate the costs… In the situation of FEI CSRs [Customer Service Representatives] taking FBC customer calls, it is dificult [*sic*] to directly assign the costs of the FEI CSR personnel. FEI charges FBC on a per transation [*sic*] basis based on the number of FBC calls handled by FEI CSR personnel.

2.1 Please confirm, or explain otherwise, whether the method for allocating costs between FBC and FEI which is provided in response to BCUC IR 4.1 in the FBC 2018 Annual Review is still applicable.

Response:

Confirmed.

On page 5 of the Application, FBC states that the sharing of gas and electric contact centre staff is forecast to produce annual savings for FBC of approximately $0.300 million.

2.2 Please provide a breakdown of the $0.300 million annual savings between one-time and on-going labour and non-labour savings.

Response:

The forecast $0.300 million in annual savings represent on-going labour savings.

3.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6; FBC 2018 Annual Review, Exhibit B-2, p. 5 and Exhibit B-3, BCUC IR 5.1

Interactive Voice Responses enhancements

On page 6 of the Application, FBC states that the estimated annual savings from new functionality introduced into the Interactive Voice Responses (IVR) system in 2017 are approximately $0.055 million.

On page 5 of the FBC 2018 Annual Review, FBC stated that new functionality will be introduced into the IVR system in 2017 and is "expected to reduce operating costs in the contact centre starting in 2018 with estimated annual savings of approximately $0.075 million."

3.1 Please explain in detail the causes/factors which resulted in FBC revising the estimated annual saving from IVR enhancement to be $0.020 million lower than what was projected in the FBC 2018 Annual Review application.

Response:

The original estimate of $75 thousand in savings was calculated by estimating the amount of calls that would be displaced from the contact centre telephony channel and resolved within the IVR.

Since that time, FBC has quantified actual savings where the customer has used the IVR to complete a transaction, displacing a call into the contact centre. There are likely additional calls avoided (and therefore additional savings) by the customer simply obtaining information through the IVR, but FBC is unable to quantify those instances with any certainty, which is why the actual savings is lower than the forecast savings.

In response to BCUR IR 5.1 in the FBC 2018 Annual Review, FBC estimated costs of $0.041 million in capital to implement the IVR system enhancements, with no expected O&M costs.

3.2 Please provide an update to the table provided in response to BCUC IR 5.1 in the FBC 2018 Annual Review for the final breakdown and description of the IVR system enhancements project cost.

Response:

The total cost of the IVR enhancements project was $29,300 for capital expenditures. There were no O&M costs. The following table shows the breakdown of the project costs. The costs were lower than anticipated due to a reduction in project scope due to not including a Credit Card payment option through a third party, as it was decided that that feature would be better offered through other available FortisBC channels.

Costs	Estimated Amount ($)	Actual Amount ($)
Contracted Labour	$25,400	$19,555
Internal Development	$11,000	$5,750
Internal Support / Testing	$5,000	$3,995
Total Labour Costs	$41,400	$29,300

3.2.1 Please provide an explanation for any significant variances identified between final IVR system enhancement project costs in the table provided in response to IR 3.2 above and BCUC IR 5.1 in the FBC 2018 Annual Review.

Response:

Please refer to the response to BCUC IR 1.3.2.

3.3 Please provide the estimated annual savings of the IVR system net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the final capital cost (i.e. annual depreciation, interest, return on equity, etc.).

Response:

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings are estimated at $0.055 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates.

	2019	2020	2026
		($000s)	
O&M savings (escalated)	$ (55)	$ (56)	$ (65)
Depreciation, Taxes and Financing	3	4	4
Net Revenue Requirements	$ (52)	$ (52)	$ (61)

1
2

4.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 7.1

SAP integration

On page 6 of the Application, FBC states that the total cost of the SAP integration project "remains on budget, estimated at $4.5 million" and that approximately $1.0 million of the cost will be allocated to FBC. In addition, FBC states O&M savings are expected to be approximately $0.9 million annually, with $0.06 million expected in FEI and $0.3 million in FBC.

4.1 Please provide the estimated annual savings of the SAP integration project (total and FBC's portion) net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

Lines 23 to 26 at page 6 of the Application state: "*Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million in FBC.*" The annual estimated O&M savings for the SAP integration project are $0.920 million in total, of which $0.340 million is allocated to FBC.

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings are estimated at $0.340 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital and income tax rates are assumed to remain at existing rates for each utility.

	FBC			Total		
	2019	2020	2026	2019	2020	2026
			($000s)			
O&M savings (escalated)	$ (340)	$ (348)	$ (401)	$ (920)	$ (942)	$ (1,084)
Depreciation, Taxes and Financing	(163)	85	141	(740)	618	788
Net Revenue Requirements	$ (503)	$ (263)	$ (260)	$ (1,660)	$ (324)	$ (296)

5.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, p. 6;

FBC 2018 Annual Review, Exhibit B-3, BCUC IR 7.1

Outage management system

FBC states on page 6 of the Application that, in late 2017, it completed a project to implement an Outage Management System (OMS) to "improve its outage response through fault location prediction using customer calls and AMI meter messages, as well as update outages from the field using the MWM [Mobile Workforce Management System]."

In response to BCUC IR 7.1 in the FBC 2018 Annual Review, FBC provided a table showing a breakdown and description of the OMS project cost, including how much of the cost is capital and how much is O&M.

5.1 Please provide an update to the table provided in response to BCUC IR 7.1 in the FBC 2018 Annual Review for the final breakdown and description of the total OMS project cost, including how much of the cost was capitalized and how much was expensed.

Response:

FBC is unable to provide a final breakdown of the total actual cost for the OMS project, separate from the overall cost of the Advanced Distribution Management System (ADMS) initiative which also includes the MWM system. Many of the activities to implement both the OMS and MWM were running parallel in nature and timing, making it not feasible to accurately track the costs specifically related to the OMS.

FBC provides in the table below an update on the total costs for the overall ADMS initiative, including both OMS and MWM.

	Planned	Actual
	($ thousands)	
Capital Implementation Costs		
Hardware	$ 96.3	$ 3.9
Software Licensing	487.6	529.7
Vendor Professional Services	368.6	448.5
Project Management	136.5	167.1
Labour	459.0	802.5
Training and Change Management	30.7	267.6
Capital Costs	1,578.7	2,219.4
Contingency	236.8	-
Project Total	$ 1,815.5	$ 2,219.4
O&M Implementation costs		
Training	$ 98.3	N/A

For the ADMS project as a whole, the reasons for the higher costs included additional internal labour for development and higher change management activities. There were also additional licensing needs due to added end users and vendor professional services that arose as changes in the scope of the project were identified to better fit the needs of the business. Ongoing support required after initial deployment to support a system bug fix release caused additional costs.

FBC did not separately track the O&M implementation costs; they are included in the formula O&M expenses.

5.1.1 Please provide an explanation for any significant variances identified between final OMS project costs in the table provided in response to IR 5.1 above and BCUC IR 7.1 in the FBC 2018 Annual Review.

Response:

Please refer to the response to BCUC IR 1.5.1.

5.2 Please discuss FBC's experience since the implementation of OMS with respect to improved outage response. How does FBC measure this improvement and what are the results before/after implementation of OMS?

Response:

The OMS provides real time visibility of customer outages as they occur through the AMI system. This has allowed the customer contact centre and system operations centre to provide more timely, specific and complete information to field crews as they are being dispatched to the predicted outage location. The outage response time with the OMS is measured from when an AMI meter or customer reports an outage to when the field crews arrive on site.

Prior to OMS, FBC would dispatch field crews to distribution related outages after the customer called to report the outage, which could be minutes to hours, and typically to a customer address. The outage response time was measured from when the customer called to when the field crews arrived on site.

The OMS streamlined the manual outage management process by predicting the location of the outage and automating the creation of outage cases as they occur. OMS eliminated the need to record and track these outages manually across multiple internal systems by acting as the central repository for all outage-related information. With the OMS, the field crews will be dispatched and arrive at outages more quickly due to improved outage notification times provided by the AMI meters rather than having to wait for customers to call to report an outage. Online and offline work order updates will be available to field crews.

While field crews will arrive at outages more quickly, since the greatest component in the calculation of outage response times is the travel time to the outage, FBC does not expect a notable improvement in measured outage response times.

Other benefits include decreasing call volumes as customers become educated about the outage map, improved safety through near real-time visualization of outages. OMS will also improve the accuracy and efficiency of producing reliability metrics, including Emergency Response Time, SAIDI and SAIFI.

Customer benefits include the provision of a website that will display near real-time outage notifications. Finally, the ADMS is estimated to result in annual O&M savings of $0.200 million.

5.3 Please provide the estimated annual savings of the OMS project net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the final capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

Justification for the ADMS project was largely based on safety and customer service improvements related to distribution outage management, including a greater situational awareness for System Control Centre and Field Operations personnel and a near real time outage map for both FBC's employees and customers. An additional benefit of the project was automation of manual processes which provided O&M savings.

For the reasons explained in the response to BCUC IR 1.5.1, FBC is unable to determine the costs and savings attributable to only the OMS component of the ADMS. The following analysis is based on the total ADMS project costs and savings.

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Annual O&M savings attributed to implementation of the ADMS project are estimated at $0.2 million and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs as a result of the project. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates.

	2019	2020	2026
	($000s)		
O&M savings (escalated)	$ (200)	$ (205)	$ (236)
Depreciation, Taxes and Financing	231	300	288
Net Revenue Requirements	$ 31	$ 95	$ 52

6.0 Reference: INITIATIVES UNDERTAKEN

Exhibit B-2, Application, Section 1.4.2, pp. 6–7

Redesigning FortisBC website

On pages 6 and 7 of the Application, FBC describes the project to redesign the FortisBC website. FBC states that estimated annual savings from the project are forecast to be $0.15 million, shared between FEI and FBC, and that it is expected to be completed in 2019.

6.1 Please provide a breakdown and description of the total project cost for the FortisBC website redesign, including how much is capital and how much is O&M.

Response:

The total costs for the project are forecast to be approximately $1.4 million, with $1.3 million for capital and $0.1 million for O&M.

The project costs are expected to be allocated between FEI and FBC based on the number of customers of each company, with FEI's share at 88 percent and FBC's share at 12 percent.

The project started in late 2017 and is expected to be completed in the first quarter of 2019.

6.1.1 Please explain how the total project cost of the FortisBC website redesign will be allocated between FEI and FBC, including FBC's estimated amount of the cost (capital and O&M).

Response:

Please refer to the response to BCUC IR 1.6.1.

6.2 Please explain the nature of the estimated $0.15 million annual savings from the FortisBC website redesign and clarify the timing of the when the savings will begin.

Response:

The estimated $0.15 million annual savings are comprised of labour savings for Communication staff involved in developing and managing web content. The new content management technology platform and workflow functionality will reduce and simplify workload. Content authoring and publishing will become much more streamlined. In addition to gaining operational efficiencies, the new technology and publishing process will help facilitate collaborative team work internally. This will reduce duplicated effort with content management and publishing processes between Communications and Web Services, help improve information flow between service teams, and optimize service levels across channels. The annual savings are anticipated to start being fully realized in 2020 after some time to operationalize the new functionality available.

6.3 Please provide the amount of the estimated $0.15 million annual savings from the FortisBC website redesign which will be allocated to FBC, including an explanation for the allocation method.

Response:

Please refer to the response to BCUC IR 1.6.1.

6.4 Please provide the estimated annual savings from the FortisBC website redesign (total and FBC's portion) net of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total project capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response:

The table below shows the O&M savings net of capital-related revenue requirements for the next two years, and for 2026. Estimated annual O&M savings are assumed to be realized 50 percent in 2019 and 100 percent in 202, and are escalated annually using the 2019 formula escalation factor. There are no incremental operating costs. Depreciation, cost of capital, and income tax rates are assumed to remain at existing rates for each utility.

	FBC			Total		
	2019	2020	2026	2019	2020	2026
			($000s)			
O&M savings (escalated)	$ (9)	$ (18)	$ (21)	$ (75)	$ (154)	$ (177)
Depreciation, Taxes and Financing	(13)	13	22	(114)	188	234
Net Revenue Requirements	$ (22)	$ (5)	$ 1	$ (189)	$ 34	$ 57

7.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.3, 2.7.2, Table 1-3, pp. 2, 7–8; Appendix B2, Table B2-1, pp. 2, 3, 5, 6, 9–11 and Table B3-1 and Figure B3-1, p. 9

FBC 2018 Annual Review, Exhibit B-2, Table 1-2, p. 7; Exhibit B-3, BCUC IR 8.1;

Capital spending results

In Table 1-2 in the FBC 2018 Annual Review application, the forecast 2017 variance between formula and actual capital was $15.306 million.

In Table 1-3 of the current Application, the actual 2017 variance between formula and actual capital was $15.799 million.

7.1 Please explain in detail the causes/factors which resulted in the actual 2017 variance in capital being $0.493 million higher than was projected in the FBC 2018 Annual Review application.

Response:

The primary cause of the variance between the 2017 Projected and Actual capital expenditures was an increase in new customer connection costs due to higher than forecast customer additions.

7.2 Please explain FBC's process for identifying the specific factors that contribute to spending in excess of the dead band (i.e. those items that are listed in Table B2-1) and how it distinguishes these items from other capital spending that is included in the formula and within the dead band.

Response:

FBC quantified the specific factors included in Table B2-1 in response to a Commission directive in Order G-38-18, which requested the breakdown as an aid to explaining the variance between actual/forecast capital expenditures and the approved formula capital amount. In creating Table B2-1, FBC has sought to provide as much clarity as it can to understand the reasons for variances from formula; however, there is in fact no definitive or correct way to identify which of its total capital expenditures are within the formula amount, within the dead band, or outside of the dead band.

The items identified as pressures within Table B2-1 are those that were not included in the capital expenditures "forecast" from the PBR Application. FBC also classifies projects reprioritized from previous years as pressures as they were not anticipated to be executed in subsequent years at the time of developing the PBR plan. Table B2-1 and accompanying

discussion in Appendix B-2 help explain the reasons that it has been necessary at an aggregate level for FBC to exceed the formula capital amount.

Although FBC has, from necessity, relied on the specific projects and timing that it identified in the capital expenditures "forecast" from the PBR Application to respond to the Commission's directive, this forecast did not form the basis of a capital "budget" for the PBR term. Rather, FBC's Base Capital was approved by the Commission to be equal to FBC Approved 2013 capital, as adjusted, which is then subject to the formula over the term of the PBR Plan. The Company anticipated, based on the flexibility endowed by entering into a PBR Plan, that it would re-evaluate the need and timing of capital projects on an ongoing basis. There is therefore no definitive way to identify what capital is inside or outside of the formula amount.

FBC relies on prudent capital management practices, and adheres to consistent policies and procedures to execute on the required capital expenditures both to support growth in customers and to maintain the safety and integrity of the gas system, regardless of whether capital expenditures fall within the dead band or outside of the dead band. FBC considers the nature and prioritization of all its capital projects. This process is described in section 3.1 of Appendix B2.

7.3 Please confirm, or explain otherwise, that other than the projects categorized as "Project re-prioritization" items on line 13 of Table B2-1, all other projects listed in Table B2-1 may be considered as "new projects that were identified to address safety, compliance, reliability issues and to replace end of life of equipment."

Response:

Not confirmed. In Table B2-1, new projects that were identified to address safety, compliance, reliability issues, and to replace end of life of equipment are specifically identified on lines 6, 7, 8, and 9. Items on the remaining lines can be characterized as unforeseen items or items driven by regulatory requirements, growth, weather events, cyber security needs, and third party requirements.

7.3.1 If not confirmed, please quantify and provide details on the specific projects which comprise the two categories of project prioritization (i.e. "catch-up on accumulation of re-prioritized work from prior years" and

"new projects to address safety, compliance, reliability and replace end of life equipment") in 2017 and 2018.

Response:

The tables below provide a breakdown of work re-prioritized into 2017 and 2018 and a summary of new projects. FBC notes the omission of the SAP Integration project from the 2018 re-prioritized work in Table B2-1 of Appendix B2 and has filed an Errata concurrently with these IR responses to correct the omission.

Additionally, the 2017 and 2018 Reprioritized work tables provide a justification for why each project was evaluated to be Essential in the year in which it was completed.

As described in Table B2-1 of the Application, essential projects include:

- Those necessary to maintain service to customers;
- Condition or obsolescence-related replacement of critical assets; and
- Planned major inspections (transmission & distribution rehabilitation programs).

All of the projects reprioritized from previous years into 2017 were in this category and were essential to complete. These projects could not be deferred to a future year, as they were required to limit increasing safety and reliability risk exposure in the system, to avoid unplanned and urgent capital work resulting from equipment failures, and to address end of life infrastructure and software.

2017 Work Reprioritized

Project	Justification	($ millions)	
Distribution Rehabilitation			
PLA1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	$0.14	
LEE1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.07	
PLA3 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.07	
PAS1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.03	
OSO1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	0.03	
			$0.35
38 Line Condition Assessment and Rehabilitation	Planned major inspections, infrastructure condition		0.35
Transmission Rehabilitation			
72 Line Rehabilitation	Planned major inspections, infrastructure condition	0.05	
74 Line Rehabilitation	Planned major inspections, infrastructure condition	0.05	
27 Line Rehabilitation	Planned major inspections, infrastructure condition	0.02	
			0.12
Distribution Line Rebuilds			
Eagle Graphite Rebuild	Infrastructure condition	0.33	
WEB2 Duchess & Newton Rebuild	Infrastructure condition	0.05	
Midgely Mountain Rebuild	Infrastructure condition	0.14	
			0.52
KRE8 Ellis St 79JC017 to 79MS016 Cable Replacement	Infrastructure condition		0.03
Glenmore Feeder 5 (Summit Drive) Capacity Upgrade	Maintain service to customers		0.3
Installation of oil containment at Keremeos substation	Mitigate environmental risk		0.23
Bulk Oil Circuit Breaker Replacement			
KER FDR1 & KER FDR 2	Condition of equipment, maintain service to customers	0.26	
LEE T3T, LEE T4T, & LEE FDR1	Condition of equipment, maintain service to customers	0.39	
			0.65
Princeton Roof Replacement	Condition of equipment		0.16
Rooftop HVAC Replacement	Compliance		0.76
Vehicle Replacement Projects	Maintain service to customers		0.2
SAP Integration (Project One)	O&M cost reductions and business efficiencies		0.32
2017 Reprioritized Work			$4.00

1

2

2018 Work Reprioritized

Project	Justification	($ millions)	
Distribution Rehabilitation			
PLA1 Feeder Rehabilitation	Planned major inspections, infrastructure condition	$0.15	
LEE1 Feeder Rehab	Planned major inspections, infrastructure condition	0.14	
PLA3 Feeder Rehab	Planned major inspections, infrastructure condition	1.12	
			$0.41
SAU7 Leon & Abbott Switcher Replacement	Condition of equipment, maintain service to customers		0.15
KRE6 Doyle Ave. Cable Replacement	Infrastructure condition		0.05
Pine Street T2 Station Smart Devices	Condition of equipment, maintain service to customers		0.17
SAP Integration (Project One)	O&M cost reductions and business efficiencies		0.59
2018 Reprioritized Work			$1.37

The table below provides a summary of new projects identified to address safety, compliance, reliability issues, and to replace end of life of equipment. These projects correspond to Line 6 through 9 of Table B2-1 of Appendix B2.

Appendix B2 Table B2-1	Line	Project	Year	($ millions)
Line 8	1	Reconfiguration of the distribution system south of the Crawford Bay substation to improve area reliability.	2018F	$0.37
	2	ROW improvements along the 30L transmission line from South Slocan substation to Coffee Creek substation to mitigate the potential for vegetation-related outages.	2018F	$0.20
Line 9	3	Replacement of Lee Terminal T4 transformer Load Tap Changer in order to extend the life of the transformer.	2017	$1.15
	4	Generating station switchyard improvements such as structure and switch replacements, concrete structure remedial work, grounding improvements for personnel safety, and transformer oil treatment to extend the life of the assets.	2018F	$0.55
Line 6	5	Compliance with OHS rules related to guarding of rotating parts - OHS 12.16 and OHS 12.3.	2017	$0.11
	6	Compliance with OHS rules related to guarding of rotating parts - OHS 12.16 and OHS 12.3.	2018F	$0.19
	7	Compliance with OHS rules for platforms - OHS 4.59 related to the load rating of hatches, plates and covers.	2017	$0.03
	8	Compliance with OHS rules for platforms - OHS 4.59 related to the load rating of hatches, plates and covers.	2018F	$0.39
Line 7	9	Compliance with OHS 9.18(3)(b) rules related to single device isolation certification.	2018F	$0.25

Line 3 in Table B2-1 shows the cumulative capital expenditure variance attributable to "System Improvements to accommodate growth" is $8.6 million.

7.4 Please explain whether the $8.6 million cumulative variance is attributable to a specific customer class or group of classes.

Response:

FBC is currently reviewing its 2018 capital expenditures forecast in conjunction with its 2019 capital budget; once FBC has completed this process, an updated IR response will be provided.

7.5 Please explain whether "System Improvements to accommodate growth" are related to customer additions or other factors related to customer growth (e.g. location).

Response:

The System Improvements to accommodate growth are related to the number of customer connections, the size of connected loads, and the geographic distribution of the connected loads. These factors are difficult to forecast when looking further into the future. Please also refer to section 2.1 of Appendix B2.

FBC states on page 3 of Appendix B2 of the Application that it anticipates capital expenditure to exceed the formula in 2019, and lists five contributing factors.

7.6 For each of the five factors listed on page 3 of the Appendix B2, please provide the amount of the forecast capital expenditure in 2019 and the expected variance from formula capital attributable to that factor in 2019.

Response:

Please refer to the response to BCUC IR 1.7.8. FBC will provide a response to this information request concurrently with that information request filing.

7.7 Please confirm, or explain otherwise, that capital expenditures to catch up on an accumulation of work re-prioritized from previous years is not a factor for why 2019 capital expenditures are anticipated to exceed the formula, given that this is not one of the factors listed on page 3.

Response:

Please refer to the response to BCUC IR 1.7.2.

7.7.1 If confirmed and excluding the projects identified in Table B3-1 as delayed beyond the PBR term, does this mean that FBC is otherwise "caught up" on work that had been re-prioritized from previous years by 2019? Please explain.

Response:

Please refer to the response to BCUC IR 1.7.8. FBC will provide a response to this information request concurrently with that information request filing.

7.8 Please provide total forecast capital expenditures in 2019 and the amount which is anticipated to exceed the formula.

Response:

The variance between forecast capital spending and the formula amount for 2019 that was forecast at the time of the 2018 Annual Review was approximately $10.4 million. FBC is currently finalizing its 2019 capital budget; once FBC has completed this process, an updated IR response will be provided.

On pages 5 and 6 of the Appendix B2 of the Application, FBC provides a list of work re-prioritized from previous years into 2017 and 2018 respectively.

7.9 Please explain whether the variance between formula and actual capital spending would have exceeded the capital dead band in years prior to 2017 if work had not been re-prioritized.

Response:

The table below shows the variances in capital expenditures assuming the initially-planned timing of projects re-prioritized from 2015 and 2016. The capital spending would have exceeded the dead band beginning in 2016.

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 42,774	$ 42,193	$ 581	$ 46,250	$ 42,384	$ 3,866	$ 48,430	$ 42,874	$ 5,556
Pension/OPEB	6,396	6,396	-	4,253	4,253	-	3,674	3,674	-
Total	$ 49,170	$ 48,589	$ 581	$ 50,503	$ 46,637	$ 3,866	$ 52,104	$ 46,548	$ 5,556
One-Year Variance			1.20%			8.29%			11.94%
Two-Year Variance Before Adjustment						9.49%			20.23%

	2017			2018			Cumulative		
	Actual	Formula	Variance	Forecast	Formula	Variance	Actual	Formula	Variance
Formula Capital	$ 55,362	$ 43,254	$ 12,108	$ 54,606	$ 43,818	$ 10,788	$247,423	$214,523	$ 32,900
Pension/OPEB	3,539	3,539	-	3,620	3,630	-	$ 21,482	$ 21,492	-
Total	$ 58,901	$ 46,793	$ 12,108	$ 58,226	$ 47,448	$ 10,778	$268,905	$236,015	$ 32,890
One-Year Variance			25.88%			22.72%			13.94%
Two-Year Variance Before Adjustment			46.10%			48.59%			

In adjusting the projects for inflation, FBC used the annual average (actual) CPI and AWE values, weighted by the same factors used to escalate the capital formula. Cumulatively, capital expenditures increased by $0.135 million compared to undertaking the projects in 2015 and 2016.

In response to BCUC IR 8.1 in the FBC 2018 Annual Review, FBC explained that Contributions in Aid of Construction (CIAC) are excluded from the capital expenditures formula envelope in the PBR plan. FBC provided a table which show capital expenditures for years 2014 to 2016 actual and 2017 forecast assuming the capital formula was net of CIAC.

7.10 Please provide 2017 actual and 2018 forecast capital expenditures net of CIAC in the same format as the response to BCUC IR 8.1 in the FBC 2018 Annual Review.

Response:

The 2017 actual and 2018 forecast capital expenditures net of CIAC are shown in the table below. The "Formula" CIAC values assume the 2013 base value for CIAC to be the approved 2013 CIAC value, escalated using the same factors as formula capital.

	2017			2018		
	Actual	Formula	Variance	Forecast	Formula	Variance
Formula Capital	$ 59.053	$ 43.254	$ 15.799	$ 55.212	$ 43.818	$ 11.394
CIAC	(12.533)	(11.431)	(1.102)	(12.239)	(11.580)	(0.659)
Pension/OPEB	3.539	3.539	-	10.649	10.649	-
Total	$ 50.059	$ 35.362	$ 14.697	$ 53.622	$ 42.887	$ 10.735
Variance			41.56%			25.03%
Variance excluding CIAC			33.76%			20.92%

In Figure B3-1 in Appendix B2 of the Application, FBC states that projects are assigned one of three capital priority classifications: "Mandatory", "Essential", and "Flexible."

FBC states on page 6 of Appendix B2 of the Application that the priority classification for the SAP Integration is "Project One."

7.11 Please define what the "Project One" priority classification assigned to the SAP Integration is, including why the SAP Integration was not assigned one of the three capital priority classifications in Figure B3-1.

Response:

The internal name of the project was changed from "SAP integration" to "Project One" and was presented for clarification. The classification should have read "Essential".

On page 10 of the Appendix B2 of the Application, FBC states that it is implementing an Asset Investment Planning (AIP) tool in 2018.

7.12 Please provide a breakdown and description of the AIP tool project costs, including a breakdown between one-time and ongoing capital and O&M costs.

Response:

The table below details the total actual capital costs, and the forecast annual operating cost. The costs are separated to show the allocation of costs between FEI and FBC. The costs for

AIP implementation for Gas System assets and Electric Network assets were allocated 100 percent to the respective utilities. The allocation of costs for AIP implementation for shared services (Information Systems, Fleet, Facilities) is allocated based on the employee count of each of the utilities (77% FEI and 23% FBC).

Business Unit	Actual Capital (FEI) ($million)	Actual Capital (FBC) ($million)	Total Actual Capital ($million)	Annual Operating Cost FEI ($000)	Annual Operating Cost FBC ($000)
PHASE 1 AIP Implementation					
Gas System Assets	1.89	0	1.89	159	0
PHASE 2 AIP Implementation					
Electric Network Assets	0	0.78	0.78	0	67
Information Systems	0.44	0.14	0.58	25	7
Facilities, Fleet	0.11	0.04	0.15	6	2
Phase 2 Total	**0.55**	**0.96**	**1.51**	**31**	**76**
Project Total	**2.44**	**0.96**	**3.40**	**190**	**76**

7.13 Please provide the capital priority classification (as set out in Figure B3-1 of Appendix B2) for the AIP tool.

Response:

FBC classified the AIP tool in the Essential category.

7.14 Please clarify whether the AIP tool is expected to produce annual savings for FBC. If yes, please provide the expected amount of annual savings.

Response:

The fundamental justification for an Asset Investment Planning solution is that it produces an optimized investment portfolio for given resource constraints, whether financial, time, labour or risk-related. While the implementation of the AIP solution within FBC was not justified on the basis of O&M and/or capital savings, FEI did consider the potential cost benefits of the solution.

Other users of AIP solutions have typically experienced a 1 percent to 10 percent "efficiency improvement" in capital investments following the implementation of an AIP tool. While this efficiency could result in overall reduced capital investments, in most cases users report replacing lower priority/value work that is screened out by the tool with higher priority/value work that was identified by the tool. Similarly, FortisBC expects that with the transition from the current manual and labourious project planning, prioritizing and scheduling process to a more robust automated solution would have similar benefits. To be conservative, FortisBC has estimated a 1 percent reduction of total capital expenditures could result from this optimization efficiency and has classified these as soft financial benefits. The total efficiency is, therefore, $0.7 million annually on a portfolio of approximately $70 million, starting in 2020. While these are not "cost savings" in a traditional sense, they are of value to the organization in that they represent more optimally allocated capital investments.

7.15 Please provide the expected amount of annual savings from the AIP tool of: i) any annual incremental operating costs which are expected; and ii) revenue requirement impacts from the estimated total project capital cost (i.e. annual depreciation, interest, return on equity, etc.)

Response

In its response to BCUC IR 1.7.14, FBC explains that the value of an AIP tool is a more optimal allocation of capital investment, and not "cost savings" in a traditional sense.

Based on the costs presented in the response to BCUC IR 1.7.12, the table below shows the O&M and capital-related revenue requirements for the next two years and for 2026. O&M expense of $0.076 million is escalated annually using the 2019 formula escalation factor. Depreciation, cost of capital and income tax are assumed to remain at existing rates.

	2019	2020	2026
		($000s)	
O&M Expense (escalated)	$ 76	$ 78	$ 90
Depreciation, Taxes and Financing	28	100	130
Net Revenue Requirements	$ 104	$ 178	$ 219

8.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application, Section 1.4.3.2, p 10

Treatment of capital spending outside of the dead band

On page 10 of the Application, FBC states:

> Accordingly, FBC added 17.64 percent of its 2018 formula capital, or $8.372 million to its opening plant in service for 2019 so that the two-year cumulative capital variance is within the two year dead band of 15 percent. FBC also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($8.372 million), such that the earnings sharing with customers is increased (see section 10 of the Application). In this way, there is no earnings sharing on the amount by which FBC exceeded the dead band.

8.1 Please confirm, or explain otherwise, that FBC is requesting approval to remove the 2018 capital expenditures in excess of the two-year cumulative dead band from the earnings sharing calculation for 2018 and add it to FBC's opening 2019 plant additions balance.

Response:

Similar to other components of the PBR Plan that are reflected in FBC's proposed 2019 rates, FBC does not believe that further approval is necessary for the treatment of capital outside the dead band. FBC is treating the capital outside the dead band as approved by the PBR Decision (summarized on pages 9 to 13 of FBC's Annual Review for 2018 Rates), and as further confirmed by Commission Order G-38-18. Section 1.4.3.2 of the Application discusses this treatment and the determinations made in the aforementioned orders.

9.0 Reference: EVALUATION OF THE PBR PLAN

Exhibit B-2, Application; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 3.1

Staffing levels

In response to BCUC IR 3.1 in the FBC 2018 Annual Review, FBC provided a table showing the actual average full-time equivalents (FTEs), headcount and unfilled vacancies for years 2013 to 2016 and projected/forecast average FTEs, headcount and unfilled vacancies for years 2017 and 2018.

9.1 Please provide actual average FTEs, headcount and unfilled vacancies for actual 2017, projected 2018 and forecast 2019 in the same format as the response to BCUC IR 3.1 in the 2018 Annual Review.

Response:

The requested information is provided in the table below.

	Average FTEs	Headcount	Unfilled Vacancies
2013 Actual[1]	421	482	8
2014 Actual[1]	492	511	21
2015 Actual	518	511	9
2016 Actual	495	488	10
2017 Actual	503	512	14
2017 Projected	502	517	n/a
2018 Projected	518	530	n/a
2019 Forecast	n/a	n/a	n/a

Note: [1] 2013 and 2014 levels staffing impacted by labour disruption.

The variance between the 2017 Projected and Actual Average FTEs and Headcount was negligible.

For the 2018 projected headcount/FTE, factors such as unanticipated staff turnover, timing of recruitment activities (i.e., being able to successfully recruit staff), changing business priorities (i.e., position no longer required) and substituting internal labour with consultants on a short term basis may affect staffing levels previously forecast. In some areas like the Customer Service department, forecasting headcount is particularly challenging given the prevalence of part-time and temporary employees. For the Customer Service department, the average FTE measure is more relevant and meaningful than the headcount measure, as headcount is measured at a specific point in time (i.e., December 31, 2016), making it difficult to forecast when part-time and temporary employees are involved.

For 2018, staffing levels are expected to increase from 2017 primarily due to increased staffing in the Generation and Operations and Engineering departments. Increases are expected to support capital activities, Mandatory Reliability Standards, succession planning and additional apprentice hires.

For 2019, at this time, staffing levels are expected to remain consistent with 2018 levels.

With regard to the Unfilled Vacancies information requested, FBC understands "Unfilled Vacancies" to mean existing positions that become temporarily vacant due to turnover. For FBC, the proxy to measure this is by taking the number of job bulletins identified as for "replacement" in a given year and calculating how long the job bulletins are vacant. The days vacant estimated are then converted to an FTE basis. However, FBC is unable to determine specifically for all the job vacancies in a given year how many are related to O&M or Capital, or whether in the interim the vacancy was filled by the use of a contractor or a consultant, or by additional overtime (paid or unpaid) by existing employees. Due to the difficulties described, FBC has not forecast Unfilled Vacancies (i.e., 2018 Projected, 2019 Forecast).

9.1.1 Please provide an explanation for: i) projected/forecasted 2018 and 2019; and ii) any significant variances identified between projected and actual 2017.

Response:

Please refer to the response to BCUC IR 1.9.1.

B. LOAD FORECAST AND REVENUE AT EXISTING RATES

10.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.3, p. 18; Table 3-1,p 20; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.7

Demand side management and other savings

On page 18 of the Application, FBC states:

> The forecast of gross system energy load includes the impacts of forecast energy savings, which includes Demand Side Management (DSM) savings, the Customer Information Portal (CIP), the Advanced Metering Infrastructure (AMI) program and future rate changes.

On page 20 of the Application, FBC provides Table 3-1 showing DSM and other savings:

Line No.	Description	DSM	AMI	CIP	Rate-Driven	Total
1	Residential	(10)	8	(4)	(0)	(7)
2	Commercial	(21)			(0)	(21)
3	Wholesale	(2)			(0)	(2)
4	Industrial	(3)				(3)
5	Lighting	(3)				(3)
6	Irrigation	(0)				(0)
7	Net	(39)	8	(4)	(0)	(36)
8	Losses	(3)	(5)			(9)
9	Gross Load	(42)	2	(4)	(0)	(44)

In response to BCUC IR 17.7 in the FBC 2018 Annual Review, FBC states that "CIP savings are calculated by taking the before-savings load and then multiplying it by the annual CIP cumulative target" FBC also shows a table illustrating CIP savings calculation, with a CIP cumulative target of 0.3 percent for 2018.

10.1 Please confirm, or explain otherwise, that the CIP savings calculation methodology and CIP cumulative target remains the same in this Application as in the FBC 2018 Annual Review.

Response:

Confirmed.

10.1.1 Please provide the CIP savings calculation for 2019.

Response:

The 2019 CIP value was calculated by taking the 2019 Before-Savings Residential load of 1,365 GWh and multiplying it by the CIP cumulative target of 0.3 percent. The equation is below:

$$2019\ CIP\ Savings = 1{,}365\ GWh \times 0.3\% = 4\ GWh$$

11.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, p. 6; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.3; FBC Application for Acceptance of 2018 DSM Expenditures, Exhibit B-1, Table 1, p. 4

DSM and other savings

FBC states on page 6 of Appendix A3 of the Application that "the forecast DSM savings is consistent with the Company's 2018 DSM Expenditure Schedule, which was approved by Order G-113-18."

In response to BCUC IR 17.3, in the FBC 2018 Annual Review, FBC explains that "The main reason for the difference is that the 2017 Forecast presents the DSM savings numbers as cumulative starting in 2016 (DSM savings are embedded in historical data), whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately)."

In FBC's Application for Acceptance of 2018 DSM Expenditures (2018 DSM Expenditures) dated November 15, 2017, FBC includes Table 1 showing the estimated DSM savings by customer class from the2018 DSM expenditure schedule:

Table 1: Proposed 2018 DSM Expenditure Plan

		2017 Approved		2018 Plan			2018/17 Difference	
		Savings MWh	Cost ($000s)	Savings MWh	Cost ($000s)	TRC[4] B/C Ratio	Cost ($000s)	% Diff
1	**Sector**							
2	Residential	10,493	2,718	7,132	2,486	1.4	-231.6	-9%
3	Commercial	13,666	3,131	19,165	3,473	2	341.6	11%
4	Industrial	1,556	309	1,188	496	2.8	187.2	61%
5	**Subtotal**	**25,715**	**6,158**	**27,486**	**6,456**	**1.8**	**297.2**	**5%**
6	Supporting Initiatives		674		742		67.9	10%
7	Portfolio		777		743		-34.2	-4%
8	**Total**		**7,610**		**7,940**	**1.6**	**330.8**	**4%**

11.1 Please provide an update to FBC's response to BCUC IR 17.3 in the FBC 2018 Annual Review proceeding, including a reconciliation of the DSM savings reported in the Application versus those estimated in the 2018 DSM Expenditures application

Response:

As discussed in FBC's response to BCUC IR 1.17.3 in the FBC Annual Review for 2018 Rates proceeding, the savings values are not directly comparable between the 2018 DSM

Expenditures plan savings (27,486 MWh) and the Forecast DSM savings values (14 GWh in 2018S). The forecast is based on the DSM Expenditures plan savings. The difference occurs as a result of the way that the DSM Plan savings are presented, attributed, and disaggregated in the load forecast.

The main reason for the difference is that the 2018 Forecast in the Application presents the DSM savings numbers as cumulative starting in 2018 (DSM savings are embedded in historical data), whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately).

The DSM Plan represents annualized energy savings for the DSM projects, by major customer sector, planned to be undertaken in that calendar year only. The forecast presented in FBC's Annual Review factors in the timing of DSM projects: as some of the DSM project savings are attributed to the year following the project. For example, if a project with 12,000 kWh of savings was completed in December 2017, the DSM Plan shows all of those savings in 2017. The forecast numbers, however, reflect only 1/12 of the savings in 2017 (1,000 kWh of savings in December 2017) and the remaining 11/12 of the project's savings are reflected in 2018 (11,000 kWh of savings from January to November 2018). Overall, as a result of pro-rating when the savings land, the 14 GWh savings in 2018S is approximately one half of the 2018 DSM Expenditures plan savings of 27,486 MWh.

Finally, FBC disaggregates a number of sub-categories of DSM for forecasting purposes in the Application, which are not shown in the DSM Expenditure plan savings. For example, "Residential" in the plan savings includes the residential portion of the "Wholesale" savings (for the City of Penticton and the other municipal utilities) presented in the load forecast. Similarly, the "Commercial" plan savings contain the "[Street] Lighting" and "Irrigation" values shown separately in the load forecast. The forecast also isolates the (line) "Losses" associated with the DSM program savings.

12.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.7, pp. 28-30

System losses

On page 28 of the Application, FBC states:

> System losses consist of:
>
> - Losses in the transmission and distribution system;
> - Company use;
> - Losses due to wheeling through the BC Hydro system; and
> - Unaccounted-for energy (meter inaccuracies and theft).
>
> Consistent with past practice, FBC assumed a loss rate of 8 percent of gross load, before the AMI impact, which is explained below. The 8 percent loss rate was based on a loss study that was conducted in 2012, which is in line with the loss rate that FBC is recording on an annual basis. FBC is currently working on an updated loss study that will utilize AMI data. The updated study is projected to be complete for the 2020 forecast.

12.1 Please provide a breakdown of system losses in GWh and as a percentage of load for each year in the PBR term, attributed to losses, company use, wheeling losses and unaccounted for energy.

Response:

The following table provides a breakdown of system losses in GWh and as a percentage of gross load for each year in the PBR term, through the end of June 2018. Losses are forecast on an aggregate basis, and therefore the breakdown beyond June 2018 is not included in the table below. Note that the table represents actual system losses, as FBC does not have a breakdown of normalized losses.

(GWh)	2014	2015	2016	2017	YTD June 2018
Gross Load	3,450	3,384	3,387	3,596	1,785
Station Service Plants 1-5	6	6	5	6	3
Company Use	7	7	7	7	4
BC Hydro Losses (ARWA)	51	46	46	58	40
FortisBC T&D Losses (including meter inaccuracies and theft)	207	209	208	218	98
% of Gross Load					
Station Service Plants 1-5	0.2%	0.2%	0.2%	0.2%	0.2%
Company Use	0.2%	0.2%	0.2%	0.2%	0.2%
BC Hydro Losses (ARWA)	1.5%	1.3%	1.4%	1.6%	2.2%
FortisBC T&D Losses (including meter inaccuracies and theft)	6.0%	6.2%	6.1%	6.1%	5.5%

12.1.1 Please explain how this breakdown is calculated.

Response:

FBC forecasts total System losses as 8 percent of gross load, before the AMI impact. The 8 percent loss rate was based on a loss study that was conducted in 2012, and is consistent with the loss rate that FBC is recording on an annual basis.

Station Service for Plants 1 through 5 is calculated from meter readings at the plant. Company use is calculated from meter readings taken from all of the applicable FBC properties. BC Hydro Losses are physical loss schedules delivered to BC Hydro on an hourly basis as calculated under the Amended and Restated Wheeling Agreement between the Company and BC Hydro.

FortisBC T&D Losses, which includes metering inaccuracies and theft, are calculated as total system losses less Station Service for Plants 1-5, Company Use, and BC Hydro Losses.

13.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.7.1, pp. 29–30; FBC 2018 Annual Review, Exhibit B-3, BCUC IR 17.4

AMI savings

On page 29 of the Application, FBC states: "The 2017 AMI impact to losses related to theft detection and deterrence is 3.9 GWh, which is consistent with the original forecast. The 2017 loss figures are embedded in the 2018 – 2019 loss figures noted in Table 3-4."

On page 29 of the Application, FBC provides Table 3-4 showing system losses before and after AMI:

Table 3-4: System Losses Before and After AMI, 2013 – 2019

		Before AMI			After AMI		
Line No.	Year	Normalized Actuals and Before-Savings Gross Load	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	Incremental AMI Impact (GWh)	% of Gross Load	Losses (GWh)
1	2013 Actual	3500.0	7.95%	278.1			
2	2014 Actual	3433.6	7.86%	269.9			
3	2015 Actual	3446.2	7.91%	272.5			
4	2016 Actual	3480.3	7.87%	274.1			
5	2017 Actual	3511.8	8.02%	281.8			
6	2018 Seed	3570.0	8.03%	286.6	(4.2)	7.89%	281.8
7	2019 Forecast	3601.6	8.06%	290.5	(7.6)	7.84%	282.5

In response to BCUC IR 17.4 in the 2018 Annual Review, FBC provides the forecast loss reduction provided as part of the AMI CPCN application (as adjusted by Order C-7-13):

	2013	2014	2015	2016	2017	2018	2019	2020	2021
					(MWh)				
As Filed	(4,628)	(2,342)	(3,261)	(3,636)	(5,241)	(4,062)	(3,148)	(2,440)	(735)
Adjusted by Order C-7-13	(3,471)	(1,757)	(2,445)	(2,727)	(3,931)	(3,047)	(2,361)	(1,830)	(551)

13.1 Please confirm, or explain otherwise, that the 3.9 GWh 2017 AMI losses related to theft detection are incorporated into the 2018 seed forecast.

Response:

The 2017 AMI losses of 3.9 GWh (3,931 MWh, above) are not incorporated into the 2018 Seed forecast. The AMI impacts are incremental to the losses before AMI in each forecast year. Therefore, the forecast does not include any AMI impacts that have been actualized. Forecast

losses of 3,047 MWh and 2,361 MWh are included in the 2018S and 2019F forecasts, respectively.

13.2 Using the forecast loss reduction from the AMI Certificate of Public Convenience and Necessity (CPCN) application, please explain how the incremental AMI impact in Table 3-4 of the application for 2018 Seed and 2019 Forecast are calculated.

Response:

The AMI impact for 2018 Seed in row 6 of Table 3-4 is based on the forecast change in the number of theft sites from 2017 to 2018 as forecast in the AMI CPCN, multiplied by the assumed annual energy usage per theft site (as modified by Order C-7-13). The AMI impact in 2019 in row 7 of Table 3-4 is the cumulative amount of the 2018 seed year and the 2019 forecast year.

Please note, Exhibit B-2, Application, Table 3-4 showed an AMI impact of (4.2) GWh for 2018 Seed and (7.6) GWh for 2019 Forecast, as well as After-AMI losses of 281.8 GWh for 2018 Seed and 282.5 GWh for 2019 Forecast. The correct values are an AMI impact of (3.0) GWh in 2018 Seed and (5.4) for 2019 Forecast, as well as After AMI losses of 282.5 GWh for 2018 Seed and 282.8 GWh for 2019 Forecast. As well, 2019 Forecast losses before AMI have been amended to exclude the cumulative AMI impact from 2018. Typographic errors do not affect the forecast, as can be seen by comparing the 2018S and 2019F loss values in Table 3-3 of the Application with the corrected Table 3-4 below. FBC has provided the corrected table in the Errata filed concurrently with these IR responses.

Table 3-4: System Losses Before and After AMI 2013-2019

			Before AMI			After AMI	
Line No.	Year	Normalized Actuals and After-Savings Gross Load (GWh)	% of Gross Load	Normalized Actual and Forecast Losses (GWh)	AMI Impact (GWh)	Losses (GWh)	% of Gross Load
1	2013 Actual	3,500.0	7.95%	277.9			
2	2014 Actual	3,433.6	7.86%	269.9			
2	2015 Actual	3,446.2	7.91%	272.5			
4	2016 Actual	3,480.3	7.87%	274.1			
5	2017 Actual	3,511.8	8.02%	281.8			
6	2018 Seed	3,570.0	8.00%	285.5	(3.0)	282.5	7.91%
7	2019 Forecast	3,601.6	8.00%	288.2	(5.4)	282.8	7.85%

On page 30 of the Application, FBC states: "FBC has implemented its energy balancing program, and is also leveraging the tamper detection functionality of the AMI system for theft identification."

13.3 Please discuss the energy balancing program, the effects this will have on load forecasts and the timeframe in which FBC expects these effects will be observed.

Response:

Consistent with the description of activities provided in the AMI CPCN application, FBC is now leveraging the AMI system to conduct energy balancing analyses on select portions of the distribution system to identify and deter energy theft. It is projected that these activities will result in a reduction of 4.7 GWhs related to energy theft between 2019 and 2021. This is consistent with the forecast provided in the AMI CPCN application as adjusted for the determinations in Order C-7-13 which included a reduction in the assumed annual energy losses per theft site to 113,000 kWh. FBC expects that its energy balancing activities will continue to have a mitigating impact on energy theft, both in terms of detection and deterrence, for the foreseeable future.

14.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.1, p. 22; Appendix A2, p.7; Appendix A3, pp.3–4

Residential Use Per Customer (UPC)

On page 22 of the Application, FBC provides Figure 3-2 showing normalized after-savings residential Use Per Customer (UPC). In Figure 3-2, the UPC for 2017 is 11.42 GWh.

On page 7 of Appendix A2, FBC provides Table 4 showing normalized after-savings UPC:

MWh/Customer	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
Residential	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.30	11.27

On page 3 of Appendix A3, FBC states: "FBC reviews the forecast methods on an annual basis and found that there was no trend in the most recent three years of UPC data and therefore applied a three year average. FBC uses the most recent UPC data since the UPC can be influenced by technology and customer behaviour patterns that are changing on an ongoing basis."

On page 4 of Appendix A3, FBC provides Table A3-3 showing the results of the residential UPC regression:

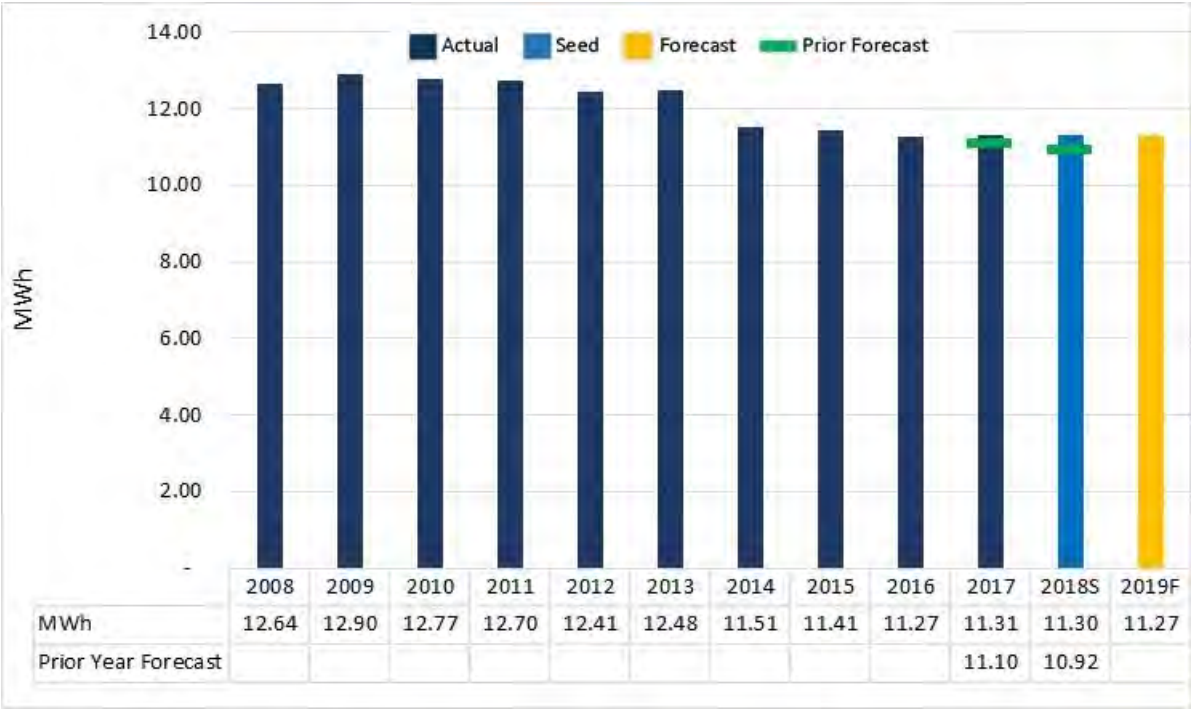
Regression	UPC
Start Year	2015
End Year	2017
R^2	0.00
Adjusted R^2	-1.00
df	2
Intercept	4
Slope UPC	0.00

14.1 Please reconcile the residential normalized after savings UPC for 2017 in Figure 3-2 (11.42) and the 2017 UPC found in Appendix A2 Table 4 (11.31).

Response:

Figure 3-2 erroneously showed the 2017 Normalized After-Savings UPC as 11.42 MWh. The correct value is 11.31 MWh, which is shown in Exhibit B-2, Appendix A2, Table 4. This typographical error does not affect the load forecast. Figure 3-2 has been corrected below.

Figure 3-2: Normalized After-Savings Residential UPC (MWh)



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
MWh	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.30	11.27
Prior Year Forecast										11.10	10.92	

14.2 Please explain which 2017 UPC value (11.42 or 11.31) is used to perform the UPC trend analysis, and whether the results differ using the two different values.

Response:

Please refer to the response to BCUC IR 1.14.1.

14.3 What are the main reasons for the forecast decline in residential UPC year-over-year from 2017 to 2019F? Please discuss.

Response:

The before-savings UPC forecast is developed using a three-year average of historic actuals. The UPC is then forecast to remain constant. DSM and other savings are deducted from the before-savings forecast, resulting in the slight decline in 2018 and 2019.

14.4 Please discuss the reasons why the 2017 actual residential UPC and the forecast 2018S residential UPC are greater than those forecasted in the FBC 2018 Annual Review.

Response:

FBC cannot definitively explain the approximately 0.3 percent increase in residential UPC from 11.27 MWh in 2016 to 11.31 MWh in 2017. Any change in residential UPC in a given year is a result of many factors that may be both compounding and offsetting.

For any given year, input data will exhibit some degree of variability. FBC believes the current approach of calculating the three-year average of historical UPCs as a proxy for the future before-savings UPC is appropriate. By averaging the most recent data, annual fluctuations can be minimized and smoothed out. A smoothing technique such as averaging is a common and well established practice to minimize year over year fluctuations.

14.4.1 Please discuss how FBC factored in the reasons for underestimating residential UPC in 2017 into its residential demand forecast for 2019.

Response:

FBC cannot definitively explain the underestimation of the 2017 residential UPC. Changes in the residential UPC in a given year are a result of many factors that may be both compounding and offsetting. As a result FBC did not factor in any reasons for underestimating the 2017 residential UPC. The 2017 UPC is the actual UPC and is calculated by taking the actual normalized load and dividing it by the actual annual average customer count.

FBC notes that the normalized 2017 UPC was used as an input to the 2019 UPC forecast, so the causes of the variance are now incorporated into the forecast.

15.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, p. 6

Lighting

On page 6 of Appendix A3, FBC provides Table A3-6 showing the results of the lighting regression:

15.1 Please confirm, or otherwise explain, that the results of lighting trend analysis are based upon lighting load, and not lighting UPC, as noted in Table A3-6.

Response:

Confirmed. The results of the lighting trend are based on the historic lighting loads and not the UPC. Exhibit B-2, Appendix A-3, Table A3-6 showed UPC in the table heading instead of LGT, however this typographical error does not affect the load forecast. Table A3-6 has been corrected below.

Table A3-6: Results of Lighting Trend Analysis

Regression	LGT
Start Year	2013
End Year	2017
R^2	1.00
Adjusted R^2	0.99
df	4
Intercept	(174,942)
Slope	93.60
Slope CoK Event	2,134

15.1.1 Please explain how DSM such as LED street lighting technology is properly accounted for to produce 2018S and 2019F.

Response:

FBC notes that Table A3-6 represents the lighting forecast equation before DSM savings.

Table A2-7 shows the resulting Before-Savings lighting load forecast of 16,081 MWh for 2018S and 2019F, as well as the After-savings net load of 15,131 and 13,380 MWh for the same two years respectively. The load forecast reduction of 2,701 MWh reflects a major DSM project,

1 namely the Kelowna LED streetlight retrofit project, which is being incented under FBC's DSM
2 programs.

3

16.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Appendix A3, pp. 1–3

Load forecast methods

On page 1 of Appendix A3, FBC states:

> Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation. Industrial and street lighting loads are typically insensitive to the weather. Currently the residential, wholesale and commercial load classes are normalized because the associated regression results showed high R2 values for these load classes. The commercial class data is normalized from 2014 to 2017 since a correlation presented itself in those years so far, therefore all data prior to 2014 is actuals data and not normalized since it did not show a correlation to weather at that point in time.

On page 2 of Appendix A3, FBC provides regression tables showing the results of the normalized regressions for residential, wholesale, commercial, and irrigation customer classes.

16.1 For each class, please provide and explain the appropriateness of the time period over which the energy consumption data was regressed.

Response:

Consistent with past practices a ten year period was used for weather normalization for each class. FBC believes this is an appropriate time period since it is long enough to smooth out extreme weather but still short enough to adjust to changing weather patterns.

16.2 What value of adjusted R2 does FBC use as an indicator to determine statistical significance and whether the forecast is based on trend analysis or uses the historical average? Please discuss.

Response:

FBC assumes a strong correlation exists when the adjusted R^2 is approximately 80 percent or higher. A number of other factors are also considered including the size, volatility and long term past performance of the rate class. The decision to use a trend analysis or a historical average

is ultimately arrived at during discussions between the Forecast Manager, Forecast Analysts, Regulatory and other staff.

16.2.1 Do the adjusted R2 values observed for irrigation indicate a correlation between energy consumption and weather for spring and summer? Please discuss.

Response:

The adjusted R^2 values observed for the irrigation class do indicate a correlation between energy and consumption for the spring and summer months for the period from 2008 to 2017. However, in the 2018 Annual Review, Exhibit B-2, Appendix A3, Table A3-2 the summer adjusted R^2 for the irrigation class was just 0.21 indicating no correlation. FBC applies weather normalization to load classes only after high R^2 values are recorded in consecutive years, ensuring that it is an actual trend and not just a one-time event.

16.3 Please demonstrate the accuracy of FBC's load forecast in each annual review over the PBR period, and discuss its performance and the merits of looking into other forecast methods, including but not limited to time weighting data, using historical data over a longer period, or alternative forecast models.

Response:

The accuracy of FBC's load forecast in each annual review over the PBR period can be found in Exhibit B-2, Appendix A-2, Table 6-2. In preparing this response, it has come to FBC's attention that Tables 6.1 and 6.2 in Appendix A-2 are incorrect. FBC has provided the corrected tables in the Errata filed concurrently with these IR responses.

Researching and testing alternate forecast methods is both complex and time consuming. Therefore, prior to conducting such research, FBC believes that the performance of the current methods should be evaluated in comparison to industry peers to determine if further research is needed. A comparison of FBC's forecast accuracy against industry peers is shown in the table below.

Energy, GWh		2014	2015	2016	2017	MAPE
Actual	Gross	3,433	3,446	3,480	3,512	
Forecast	Gross	3,519	3,499	3,540	3,559	
Variance		-86	-53	-60	-47	
Variance %		-2.5%	-1.5%	-1.7%	-1.3%	
APE		2.5%	1.5%	1.7%	1.3%	1.8%
ITRON	Respondents	66	71	62	71	
	APE	1.5%	1.3%	1.9%	1.6%	1.6%

As shown in the table above, FBC achieved a mean absolute percent error (MAPE[1]) score of 1.8 percent on the gross demand forecast for the PBR term (2014 to 2017).

The ITRON row in the table above reflects the results of the annual ITRON survey for forecast accuracy, which includes the responses from more than 60 electric utilities. FBC does not participate in this survey. As shown in the table, the MAPE from the ITRON respondents was 1.6 percent.

FBC believes that a gross demand MAPE score of 1.8 percent is reasonable and comparable with the average from the ITRON survey. FBC therefore does not believe there is a need to conduct further research on the suitability or performance of other forecast methods.

[1] MAPE – Mean Absolute Percent Error is a commonly used and accepted metric for measuring forecast accuracy.

17.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.3, p. 24; Appendix A2, pp. 8, 10

Wholesale energy forecast

On page 24 of the Application, FBC states: "after-savings wholesale energy is forecast to increase by 6 GWh in 2018S and 14 GWh in 2019F. The increase in 2019F is partially due to commercial developments within certain wholesale customer's territories."

On page 8 of Appendix A2, FBC provides the following table, showing normalized after-saving wholesale energy:

Wholesale (GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018S	2019F
BCH Lardeau	7	6	10	6	6	6	6	6	6	8	7	7
BCH Kingsgate	3	4	3	3	5	5	5	5	5	5	5	5
City of Grand Forks	41	41	41	41	41	41	39	41	41	39	47	54
City of Nelson	107	109	90	88	80	83	81	83	80	86	77	80
City of Penticton	346	346	341	344	341	348	342	348	345	338	340	340
District of Summerland	92	78	97	96	95	98	94	97	98	98	104	107
City of Kelowna	312	324	314	329	332	94	-	-	-	-	-	-
City of Princeton	-	-	-	-	-	-	-	-	-	-	-	-
Total	908	908	895	910	899	675	567	580	574	574	580	594

On page 10 of Appendix A2, FBC presents Table 6.2 showing the historical load variance from 2012 to 2017. The wholesale variance is replicated below

Wholesale Energy (GWh)	2012	2013	2014	2015	2016	2017
Normalized	899	675	567	580	574	574
Forecast	926	935	581	593	579	585
Variance (GWh)	-27	-260	-14	-13	-5	-11
Variance (%)	-3.0%	-38.5%	-2.5%	-2.2%	-0.8%	-1.9%

17.1 Please discuss the reasons why wholesale energy load for the City of Grand Forks is forecast to grow by approximately 20 percent between 2017 and 2018S, and 14 percent between 2018S and 2019F.

Response:

In addition to FBC's annual survey of industrial and wholesale customers, FBC also conducted site visits with most of its wholesale customers in 2018. Through the combined processes of the survey and site visits FBC learned that the load for The City of Grand Forks was expected to grow by approximately 20 percent from 2017 to 2018 due to the addition of a significant new customer being added in Q2 of 2018. The increase from 2018 to 2019 is due to the full load of this new customer being realized in 2019.

17.2 Please explain why the wholesale class energy has been over forecast relative to normalized over the 2012–2017 period.

Response:

Excluding the high variance in 2013 that resulted from the City of Kelowna acquisition, the average over-forecast variance from the remaining years is approximately 2 percent. FBC cannot definitively explain the cause of a variance of this magnitude as it is a result of many factors that may be both compounding and offsetting from multiple wholesale customers each with a different mix of customers and rate classes.

FBC believes that each wholesale customer is best able to provide the most accurate forecast for their service area. To gain additional understanding FBC conducted site visits to most of the wholesale customers this year. These site visits confirmed that each wholesale utility is more knowledgeable about future changes in their service area including upcoming projects and programs that could affect their loads. For example in the case of Grand Forks, the increase in demand was explained to FBC as the result of a new project coming online in 2018. FBC does not believe that other forecast methods exist that would be able to capture these changes with any greater accuracy.

17.2.1 Has FBC identified an alternative forecast methodology to address this trend? Please discuss.

Response:

Please refer to the response to BCUC IR 1.17.2.

18.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.5.8, p. 30

Peak demand

On page 30 of the Application, FBC states: "The peak load forecast is produced using the ten-year average of historical peaks. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system."

18.1 Please provide the methodology and an illustrative example of how FBC calculates the gross load growth rate.

Response:

The gross load growth rates for actual years are calculated by taking the current year's actual gross load and subtracting the previous year's actual gross load and then dividing that number by the previous year's actual gross load.

For example,

$$2017\ Gross\ Load\ Growth\ Rate = \frac{2016\ Gross\ Load - 2017\ Gross\ Load}{2016\ Gross\ Load}$$

Numerically:

$$2017\ Gross\ Load\ Growth\ Rate = \frac{3{,}387\ GWh - 3{,}596\ GWh}{3{,}387\ GWh} = 6.2\%$$

The process is the same for the forecast years, except that before-savings load is used instead of actuals. For forecast years, the before-savings gross load is used since DSM is subtracted from the peaks once they have been calculated.

18.1.1 Please confirm, or otherwise explain, that the calculated gross load growth rate is used to escalate each historical peak.

Response:

Confirmed.

19.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Sections 3.6, 12.4.2.5, pp. 31, 118; Order G-124-17

Revenue forecast

On August 17, 2017 the BCUC issued Order G-124-17 approving FBC's application to provide a credit to customers who receive service under certain FBC Electric Tariff Rate Schedules for the 2017 charges that would otherwise have applied under those rate schedules during the period the customer was under an Evacuation Order due to wildfires.

On page 31 of the Application, FBC provides Table 3-5 showing the approved, projected and forecast revenue for 2018 and 2019.

On page 118 of the Application, FBC provides Table 12-4 showing the 2018 Flow-through deferral account additions.

19.1 Please provide the total number of customers by class which received the evacuation relief in 2017 approved by the BCUC pursuant to Order G-124-17.

Response:

The table below shows the total number of residential, commercial, and irrigation services which received evacuation relief in 2017:

FBC Rate Schedule	Number of Services[2]
Residential RS 1, 2A, 3, 3A, 95	860
Commercial Service RS 20, 21, 22A, 23A	68
Irrigation and Drainage RS 60, 61	15

FBC has provided the total number of services by rate schedule rather than number of customers because there were situations were one customer had multiple services under different rate schedules and therefore separate credit amounts on each invoice. The total actual amount of the credits provided to these customers due to the wildfires in 2017 based on Order G-124-17 was $21,536. This amount was treated as a revenue shortfall, was recorded in the

[2] In an informal response to staff dated August 15, 2018, related to the application by FortisBC Energy Inc. and FBC Application for Approval to Exempt from Applicable Residential and Commercial Tariff Charges for Customers Under Evacuation Orders and Application for Approval of Tariff Changes to Permit Relief for Customers Under Evacuation Orders, FBC stated that there were a total of 866 FBC customers (941 services); however, the updated actual total number is 868 customers (943 services).

Flow-through deferral account in 2017, and will be recovered from ratepayers in 2019 rates (as part of the calculation of the final 2017 Flow-through deferral account balance as set out in the response to BCUC IR 1.37.1).

Amortization of the $21,536 from wildfire relief embedded in the Flow-through deferral account results in a one-time rate increase in 2019 of 0.006 percent for all ratepayers or approximately $0.11 for an average residential customer in 2019.

19.2 Please provide the total impact on FBC's 2017 revenue resulting from the evacuation relief provided.

Response:

Please refer to the response BCUC IR 1.19.1.

19.2.1 As part of the above response, please identify the variance between the approved 2017 and the actual 2017 sales revenue that are due to the customer credits approved by Order G-124-17.

Response:

Please refer to the response BCUC IR 1.19.1.

19.3 Please explain how the revenue variance resulting from the evacuation relief bill credits was treated, including whether, and in what year, the variance was recorded in the Flow-through deferral account and in what year the variance will be recovered from ratepayers.

Response:

Please refer to the response to BCUC IR 1.19.1.

19.3.1 Please provide the rate impact of the amortization of the revenue variance resulting from the customer credits.

Response:

Please refer to the response to BCUC IR 1.19.1.

C. POWER SUPPLY

20.0 Reference: POWER SUPPLY

Exhibit B-2, Application, Section 4.5 and 4.6, pp. 35, 37; FBC 2018 Annual Review, Exhibit B-2, p. 37

BC Hydro Power Purchase Agreement (PPA) expense

On page 37 of the FBC 2018 Annual Review application, FBC states it "submitted a PPA nomination for the 2017/18 contract year of 642 GWh on June 27, 2017…" On page 35 of the current Application, FBC states it "submitted a PPA nomination for the 2018/19 contract year of 725 GWh on June 25, 2018…"

On page 37 of the Application, FBC states:

> BC Hydro PPA expense increased by $13.551 million in the 2019 Forecast compared to the 2018 Projected. A forecast BC Hydro rate increase of 2.6 percent on April 1, 2019 accounts for $1.480 million, whereas higher purchased volume (211 GWh) increases the 2019 Forecast expense by $13.071 million.

20.1 Please explain how FBC calculates an increase in PPA purchases by 211 GWh from 2018 to 2019, including an explanation on the volumes assumed in the Projected 2018 BC Hydro PPA expense.

Response:

BC Hydro PPA energy purchases increased from 549 GWh in the 2018 Projected to 759 GWh in the 2019 Forecast, which rounded to a 211 GWh increase. The volumes in the 2018 Projected are based on actuals through June 30, 2018 and a forecast for the remainder of the year, which may be further reduced by mitigation opportunities. This increased reliance on BC Hydro PPA energy is mainly a result of reduced Market and Contracted purchases included in the 2019 Forecast. The 2019 Forecast only includes those market purchases for 2019 that FBC was able to execute prior to filing. FBC continues to monitor system and market conditions for additional opportunities for 2019 and has included a $2 million reduction to BC Hydro expense in the 2019 Forecast to account for additional opportunities, which would reduce the BC Hydro PPA 2019 Forecast volumes, as described in Section 4.6 of the Application.

21.0 Reference: POWER SUPPLY

Exhibit B-2, Application, Section 3.7, p. 38

Wheeling expense

On page 38 of the Application, FBC provides the following table, showing wheeling expenses:

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,490	2,490	2,400
3	Creston	444	444	471
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.590	$ 4.573	$ 4.514
7	Creston	0.534	0.542	0.577
8	Other	0.048	0.165	0.144
9	Total Wheeling Expense	$ 5.171	$ 5.281	$ 5.235

On page 33 of the Application, FBC states that "the 2019 Forecast wheeling expense is forecast to increase due to increased wheeling rates."

On page 38, FBC states:

> In 2018 and 2019, ARWA costs are forecast to account for all of FBC's wheeling expense, except for $0.165 million and $0.144 million of OATT and Teck wheeling in 2018 and 2019 respectively. Increased use of both Emergency Wheeling and Teck wheeling in early 2018 caused the 2018 Projected OATT wheeling expenses to exceed Approved…. As shown in Table 4-4 above, 2019 wheeling expense is forecast to decrease by $0.022 million over 2018 Projected.

21.1 Please discuss the reasons for increased used of emergency wheeling and Teck wheeling in early 2018.

Please confirm, or otherwise explain, that 2019 wheeling expense is forecast to decrease by $0.046 million over 2018 projected.

Response:

In early 2018, FBC increased its use of Emergency Wheeling because of an unplanned transmission outage that persisted throughout the first three months of the year. FBC also increased the use of Teck wheeling above the 2018 Approved amount due to an increased

volume of Market and Contracted purchases on 71 Line. The increase in Teck wheeling is more than offset by the increase in market savings that the market purchases produced.

With that background, it is confirmed that 2019 wheeling expense is forecast to decrease by $0.046 million over 2018 projected.

D. OTHER REVENUE

22.0 Reference: OTHER REVENUE

Exhibit B-2, Application, Section 5.5, p. 41

Late payment charges

On page 41 of the Application, FBC states that beginning with 2019, it is forecasting late payment charges as part of Other Revenue. FBC states it "has historically not forecast late payment charges as part of its revenue requirement. When these charges were earned, they were flowed through to customers."

22.1 Please explain why FBC decided to forecast late payment charges as part of Other Revenue, beginning in 2019.

Response:

Historically, FBC recorded late payment charges in sales revenue and had not forecast the amounts explicitly. On January 1, 2018, FBC began to record late payment charges as Other Revenue, which is consistent with FEI's accounting treatment and is the more appropriate classification, consistent with the treatment of connection charges as non-sales revenue. FBC then began to forecast late payment charges for the 2019 revenue requirements.

22.2 Please explain and provide the 2019 impact of forecasting late payment charges as part of Other Revenue on FBC's revenue requirement, as compared to a flow through to customers as charges are earned.

Response:

The impact of forecasting late payment charges in revenue requirements is simply a matter of timing since variances in Other Revenue are included in the Flow-through deferral account. When late payment charges are forecast, the forecast reduces revenue requirements in the test year and is trued up in the following year(s). If late payment charges are not forecast, then the benefit to revenue requirement all occurs when the variance in the Flow-through deferral account is amortized into rates.

The $0.861 million forecast for late payment charges in 2019 is equivalent to a (negative) rate impact of 0.23 percent ($0.861 million divided by $370.534 million).

E. OPERATING & MAINTENANCE (O&M) EXPENSE

23.0 Reference: O&M EXPENSE

Exhibit B-2, Application, Section 6.3.3, Table 6-5, p. 46

AMI project

In Table 6-5 on page 46 of the Application, FBC compares 2014 through 2019 net AMI savings to the net savings forecast in the AMI CPCN application. Table 6-5 shows that 2019 forecast costs are $2.055 million compared to $1.951 million in the AMI CPCN application, while 2019 forecast savings are $3.216 million compared to $4.244 million in the AMI CPCN Application.

23.1 Please provide an explanation and breakdown of the $0.104 million increase in the current 2019 forecast AMI costs and $1.028 million decrease in the forecast AMI savings, compared to the forecasts in the AMI CPCN application.

Response:

Forecast post-AMI costs are approximately $0.1 million higher than CPCN due to manual disconnect and reconnect costs. The higher post-AMI costs are due to not forecasting an increase in the unit cost of manual disconnects and reconnects at substantially lower post-AMI volumes in the CPCN application.

The forecast post-AMI savings are approximately $1.0 million lower than CPCN for the reasons listed in Sections 6.3.3.1, 6.3.3.2 and 6.3.3.3, excluding the manual disconnects and reconnects reason listed above (which explains an increase in costs).

F. RATE BASE

24.0 Reference: REGULAR CAPITAL EXPENDITURES FORECAST OUTSIDE THE FORMULA

Exhibit B-2, Application, Section 7.2.2, Table 7-3, p. 55

AMI sustainment capital

On page 55 of the Application, FBC provides Table 7-3 showing 2019 forecast capital expenditures outside of the formula:

Table 7-3: 2019 Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Pension/OPEB (Capital Portion)	$ 3.630	$ 3.630	$ 3.612
2	AMI Sustainment Capital	0.265	0.324	0.937
3	Mandatory Reliability Standards Incremental Capital	0.050	0.050	2.780
4	Employer Health Tax	-	-	0.624
5	MSP Reduction	-	(0.182)	(0.182)
6	Forecast Capital Expenditures	$ 3.945	$ 3.822	$ 7.771

24.1 Please explain in detail the causes/factors for why FBC forecasts 2019 AMI sustainment capital ($0.937 million) to be $0.613 million higher than 2018 projected ($0.324 million).

Response:

The 2019 AMI sustainment capital reflects the requirement to upgrade the systems that operate the AMI network at FBC. The components of the AMI system that require upgrading include all the supporting applications, security appliances, operating systems and databases. These systems were implemented in 2012 at the beginning of the AMI project. The upgrades are required to maintain support and ensure security and reliability of the AMI network.

Sustaining capital in years leading up to 2019 was used to apply regular patching and minor support upgrades. In 2019 new versions of the supporting AMI systems will need to be implemented. The costs indicated for 2019 reflect this additional effort. The timing of this effort is consistent with other systems at FBC. Significant version upgrades to enterprise solutions, such as AMI, are normally required after 5 years.

24.2 Please clarify whether forecast 2019 AMI sustainment capital expenditures are consistent with the forecast for 2019 in the AMI CPCN application. If not, please explain why not.

Response:

FBC's 2019 AMI sustainment capital expenditures were forecast at $0.955 million in the AMI CPCN application, which is consistent with the forecast 2019 AMI sustainment capital expenditures of $0.937 million as detailed in Table 7-3 from the Application (Exhibit B-2).

25.0 Reference: CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Exhibit B-2, Application, Section 7.3, p. 56; FBC Application for a CPCN for the Corra Linn Dam Spillway Gate Replacement Project, Order C-1-17

Corra Linn Dam Spillway Gate Replacement Project

On page 56 of the Application, FBC states, for 2019 it forecasts the Corra Linn Dam Spillway Gate Replacement Project to be completed in 2021 at a cost of $66.844 million, with $14.459 million of this amount incurred in 2019.

In FBC's Application for a CPCN for the Corra Linn Dam Spillway Gate Replacement Project, FBC estimated the capital cost for the project in as-spent dollars to be $62.694 million.

25.1 Please explain in detail the causes/factors for why the current forecast to complete the Corra Linn Dam Spillway Gate Replacement Project is $4.150 million higher than what was forecast in the CPCN application. As part of your response, please include explanations for any variances/changes to project scope and/or the timing of costs if appropriate.

Response:

In response to BCUC Order C-1-17, FBC filed a Contract Finalization report with the BCUC on April 4, 2018, which addresses the increased project costs in detail. This response is intended to provide a summary of the key points outlined in the Contract Finalization report.

The Open Book Phase (OBP) of the project was completed collaboratively with HMI Canada Inc (HMI) as the design/engineer consultant, Knight Piésold (KP) as the owners engineer representing FBC, and FBC. The OBP process resulted in sufficient engineering, design, and procurement work to develop the Project scope, schedule, and contract price. HMI was required to tender approximately 70 percent of the sub-contractor costs to ensure market pricing was used to develop the contract price. The total Project cost is now a Class 1 estimate at $66.844 million, as compared to the original Class 3 cost estimate included in the Application of $62.694 million. This represents a variance of $4.15 million or approximately 7 percent, which is well within the accuracy ranges of an AACE Class 3 cost estimate and is primarily attributable to the refining and maturing of the Project definition and scope that took place through the OBP process.

The following table is provided to outline the differences in costs from the class 3 estimate to that of the class 1 estimate.

	Application (Class 3) As-Spent ($ million)	OBP (Class 1) Estimate ($ million)	Variance ($ million)
Contractor's Costs			
Engineering	2.506	2.897	0.392
Supply, Installation & Testing	19.304	22.947	3.643
Site-Support Work	10.071	10.483	0.412
Indirect Costs	0.666	0.484	(0.182)
Project Management	4.610	5.994	1.384
Subtotal	***$ 37.156***	***$ 42.805***	***$ 5.649***
Removal Cost	5.804	7.554	1.750
Construction Contingency	2.148	1.371	(0.777)
Total Contractor Costs	***$ 45.108***	***$ 51.730***	***$ 6.622***
FBC Owner's Costs			
FBC – Project Management	3.155	3.674	0.519
Generation Admin Overhead	0.589	0.505	(0.084)
Project Contingency	7.328	4.000	(3.328)
Pre-Approval Project Costs	1.081	0.934	(0.147)
Subtotal (Contractor & Owner's Costs)	***$ 57.260***	***$ 60.844***	***$ 3.584***
Allowance for Funds Used During Construction (AFUDC)	5.434	6.000	0.566
TOTAL Project Capital Costs	***$ 62.694***	***$ 66.844***	***$ 4.150***

When combined, the estimate for the supply, installation, testing, and site-support work has increased by approximately $4.1 million. The following is a brief summary of the main items:

- New hoists – The need for new hoists and associated works contributed to an increase of approximately $1.6 million. The Class 3 cost estimate in the Application was developed based on the assumption that refurbishment would be sufficient to handle the increased gate weight; however, detailed analysis and engineering of the existing hoist components could not assure the required safety factors.

- Tower and bridge reinforcements - The cost is approximately $2.5 million higher than the estimate included in the Application primarily due to additional requirements for tower and bridge reinforcements to support the new hoists.

The financial forecast of the project has changed from what was submitted in the CPCN as follows:

	2017 $ (000)	2018 $ (000)	2019 $ (000)	2020 $ (000)	2021 $ (000)	2022 $ (000)	Total $ (000)
Original CPCN Forecast	11,595	21,968	18,555	9,774	0.802	0	62,694
Revised Forecast	3,911	17,347	18,430	15,536	11,267	0.351	66,844

The revised forecast is based upon a negotiated milestone payment schedule, which was developed at the conclusion of the OBP, after the CPCN was submitted.

26.0 Reference: CPCN AND SPECIAL PROJECTS CAPITAL EXPENDITURES

Exhibit B-2, Application, Section 7.3, Table 7-4, pp. 56, 57; Appendix C, Section 3, pp. 19–20; Appendix D, Section 3, pp. 11–12

2019 plant additions

On page 57 of the Application, FBC provides Table 7-4 showing a reconciliation of capital expenditures to 2019 plant additions. The table shows that additions to plant, related to special projects and CPCNs, are expected to total $14.775 million.

FBC states on page 56 that special project and CPCN costs, which will be included in rate base in 2019, are "the portion of the UBO Project [Upper Bonnington Old Units Refurbishment Project] attributable to the refurbishment of Unit 4" and the Ruckles Substation Project, which is expected to be completed in 2018.

26.1 Please provide a breakdown of the $14.775 million special projects and CPCN additions to plant by project. Please ensure that the breakdown reconciles to the "forecast expenditures to completion" for Unit 4 of the UBO Project and the Ruckles Substation Project, as provided in Section 3 of both Appendix C and D.

Response:

The breakdown of the 2019 Special Projects and CPCN Projects Additions to Plant is provided in the table below, along with the reconciliation of the Ruckles Substation Rebuild and UBO Refurbishment Project totals to Appendix D and Appendix C, respectively. Note that the project cost table for the UBO Refurbishment Project (Appendix C, Table C-2) contains an error. Forecast AFUDC is reported at $1.188 million. The correct value of $1.198 million as seen in the table below. A correction to Appendix C, Table C-2 is included in the response to BCUC IR 1.42.1. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

Line No.	Description	2019 Corra Linn	2019 Ruckles	2019 UBO	2019 Total, Table 7-4	Project Total UBO
1	Special Projects and CPCN Capital Expenditures	$ 12.750	$ -	$ 7.449	$ 20.199	$ 30.585
2	Special Projects and CPCN AFUDC	1.709		0.373	2.082	1.198
3	Special Projects and CPCN Cost of Removal	(2.751)		(0.333)	(3.084)	(1.496)
4	Special Projects and CPCN Work in Progress	(11.708)	6.690	0.596	(4.422)	-
5	Special Projects and CPCN Additions to Plant	$ -	$ 6.690	$ 8.085	$ 14.775	$ 30.287
6						
7	Add Cost of Removal		0.223			1.496
8	Total Project Cost per Appendix D (Ruckles) and Appendix C (UBO)		$ 6.913			$ 31.783

G. FINANCIAL SCHEDULES

27.0 Reference: FINANCIAL SCHEDULES

Exhibit B-2, Application, Section 11, Schedules 11, 11.1, 12

Unamortized deferred charges and amortization (rate base and non-rate base)

27.1 In the same format as is provided in Schedules 11, 11.1 and 12 in Section 11 of the Application, please provide the previous years' information on unamortized deferred charges by starting with the Actual 2017 ending deferral account balances and including projected 2018 deferral account additions and amortization.

Response:

The requested schedules are provided below.

In the schedules FBC has reduced its 2018 forecast for two deferral accounts

- The 2017 Rate Design Application (Schedule 12.1, Line 8) deferral account is reduced by $0.398 million, as explained in the response to BCUC IR 1.36.1, and
- The 2016 Long Term Electric Resource Plan (Schedule 12.1, Line 7) deferral account is reduced by $0.037 million, based on costs to date.

These revisions will be included in FBC's Evidentiary Update.

FORTISBC INC. Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1. Forecasting Variance Accounts								
2									
3	2. Rate Smoothing Accounts								
4									
5	3. Benefits Matching Accounts								
6	Demand Side Management	$ 22,427	$ -	$ 7,900	$ (2,133)	$ (3,711)	$ 24,483	$ 23,455	
7	Deferred Debt Issue Costs	3,826	-	2	(119)	(165)	3,543	3,685	
8	Preliminary and Investigative Charges[1]	330	-	(140)	-	-	191	260	Note 1
9	Right of Way Reclamation (Pine Beetle Kill)	173	-	-	-	(173)	-	87	
10	Accounting Treatment of non-AMI Meters	2,163	-	-	-	(1,082)	1,082	1,623	
11		$ 28,920	$ -	$ 7,762	$ (2,252)	$ (5,131)	$ 29,298	$ 29,109	
12	4. Retroactive Expense Accounts								
13									
14	5. Other Accounts								
15	Pension and OPEB Liability	(17,298)	-	493	-	-	(16,805)	(17,052)	
16		$ (17,298)	$ -	$ 493	$ -	$ -	$ (16,805)	$ (17,052)	
17									
18	**Total Rate Base Deferral Accounts**	$ 11,622	$ -	$ 8,255	$ (2,252)	$ (5,131)	$ 12,493	$ 12,058	
19									

20 Note 1: Gross additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress.
1 Additions of $0.150 million - transfers of $0.290 million = $(0.140) million.

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FORTISBC INC.

Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 12

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	1. Forecasting Variance Accounts								
4	Revenue and Power Supply[(1)]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Flow-Through Accounts	(9,356)	-	(10,534)	-	7,102	(12,788)	(11,072)	
6	Pension & Other Post Retirement Benefits (OPEB) Variance	(367)	-	(617)	-	289	(695)	(531)	
7		$ (9,723)	$ -	$ (11,151)	$ -	$ 7,391	$ (13,483)	$ (11,603)	
8	2. Rate Smoothing Accounts								
9	2018 Revenue Deficiency	$ -	$ -	$ 896	$ (242)	$ -	$ 654	$ 327	
10									
11	3. Benefits Matching Accounts								
12	2014-2019 Performance Based Ratemaking Application	493	-	-	-	(246)	246	369	
13	Annual Reviews for 2015-2019 Rates	32	-	205	(55)	(102)	79	55	
14	Self-Generation Policy Application, Stage II	(19)	-	75	(20)	-	35	8	
15	Net Metering Program Tariff Update	87	-	52	(14)	(88)	38	63	
16	BCUC Residential Inclining Block Rate Report	(19)	-	3	(1)	22	5	(7)	
17	2017 Demand Side Management Expenditure Schedule Application	10	-	-	-	(11)	(1)	5	
18	2018 Demand Side Management Expenditure Schedule Application	-	2	70	(19)	-	54	28	
19	BC Hydro Application for Power Purchase Agreement with FBC	(7)	-	-	-	7	-	(3)	
20	Community Solar Pilot Project	-	51	71	(19)	(130)	(27)	12	
21	Tariff Applications	(74)	-	-	-	-	(74)	(74)	
22	Electric Vehicle Charging Stations Rate Design and Tariff Application	-	11	45	(12)	-	44	28	
23		$ 502	$ 65	$ 519	$ (140)	$ (548)	$ 399	$ 483	
24	4. Retroactive Expense Accounts								
25									
26	5. Other Accounts								
27	2014-2019 Earnings Sharing Account	(744)	-	(169)	46	615	(252)	(498)	
22	Castlegar Office Disposition	31	344	(813)	-	-	(439)	(469)	
23	BC Hydro Waneta 2017 Transactions	-	33	79	(21)	-	91	62	
24		$ (713)	$ 377	$ (903)	$ 24	$ 615	$ (601)	$ (905)	
25									
26	**Total Deferral Accounts at Short Term Interest**	$ (9,934)	$ 441	$ (10,638)	$ (358)	$ 7,457	$ (13,031)	$ (11,698)	
27									
28	Financing Costs at STI	$ (289)	$ -	$ (405)		$ 361	$ (333)	$ (311)	
29									

1 30 Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/17	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/18	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**							
2								
3	1. Forecasting Variance Accounts							
4								
5	2. Rate Smoothing Accounts							
6								
7	3. Benefits Matching Accounts							
8	CPCN Projects Preliminary Engineering	$ 130	$ -	$ 125	$ -	$ -	$ 255	$ 192
9	2016 Long Term Electric Resource Plan	382	-	233	(63)	(141)	412	397
10	2017 Rate Design Application	124	-	852	(230)	-	746	435
11	Transmission Customer Rate Design	2	-	-	-	(2)	-	1
12	2020 Revenue Requirements	-	-	225	(61)	-	164	
13	2019 - 2022 Multi-Year DSM Expenditure Schedule	-	74	115	(31)	-	158	116
14	2018 Joint Pole Use Audit	-	-	200	(54)	(29)	117	58
15		$ 638	$ 74	$ 1,750	$ (439)	$ (172)	$ 1,852	$ 1,200
16	4. Retroactive Expense Accounts							
17								
18	5. Other Accounts							
19	US GAAP Pension and OPEB Transitional Obligation	$ 2,728	$ -	$ (827)	$ -	$ -	$ 1,901	$ 2,314
20	Advanced Metering Infrastructure Radio-Off Shortfall	88	-	-	-	-	88	88
21		$ 2,816	$ -	$ (827)	$ -	$ -	$ 1,989	$ 2,403
22								
23								
24	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 3,455	$ 74	$ 923	$ (439)	$ (172)	$ 3,841	$ 3,603
25								
26	Financing Costs at WACD	$ 447	$ -	$ 198		$ (499)	$ 147	$ 297
27								
28	**Deferral Accounts Financed at AFUDC**							
29								
30	3. Benefits Matching Accounts							
31	On Bill Financing (OBF) Participant Loans	$ 9	$ -	$ (1)	$ -	$ -	$ 8	$ 9
32								
33	Financing Costs at AFUDC	$ 1	$ -	$ 1	$ -	$ (1)	$ 1	$ 1
34								
35	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50
36								
37	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,260)	$ 515	$ (9,923)	$ (797)	$ 7,146	$ (9,317)	$ (7,531)

1

28.0 Reference: FINANCIAL SCHEDULES

Exhibit B-2, Application, Section 11, Schedule 12.1, p. 88; FBC 2018 Annual Review, Exhibit B-2, p. 120

Unamortized deferred charges and amortization (non-rate base)

In the FBC 2018 Annual Review, FBC stated on page 120 of its application that its portion of the costs related to the next revenue requirement application following the end of the current PBR term will include the costs of a benchmarking study. FBC stated that it anticipates completing the benchmarking study by year-end 2018 at an estimated cost of $0.030 million in 2017 and $0.070 million in 2018. Further, on line 8 of Schedule 12.1, in Section 11, FBC forecasted a 2018 ending balance of $53,000 in the 2020 Revenue Requirements deferral account. FBC further stated, "Forecast costs for the remainder of the application and its regulatory review will be updated at a later time."

On line 13 of Schedule 12.1 in Section 11 of the Application, FBC shows that the 2019 opening balance in the 2020 Revenue Requirements deferral account is $164,000.

28.1 Please explain in detail the causes/factors which resulted in the 2019 opening balance of the 2020 Revenue Requirement Application deferral account balance to be $111,000 higher than what was projected in the FBC 2018 Annual Review application.

Response:

On a before-tax basis, the forecast 2019 opening balance in the deferral account increased by $0.125 million from the forecast in the Annual Review for 2018 Rates. Of this, $0.100 million is the estimated cost to conduct a depreciation study for filing with the 2020 Revenue Requirements. Income tax on the account was affected by the change in the tax rate, which was not included in the initial filing for 2018 Rates, and by an overstatement of the tax impact for this account, which was corrected in the compliance filing for 2018 rates.

28.2 Please describe the nature of the forecast $975,000 in additions to the 2020 Revenue Requirement Application deferral account which is shown on line 13 of Schedule 12.1 in Section 11 of the Application.

Response:

The forecast additions in 2019 include the Commission's direct costs, participant assistance cost awards, notice publication costs, consulting and expert fees, external legal counsel fees, courier and miscellaneous administrative costs.

28.2.1 Please discuss the expected timing for when FBC will provide an update on the forecast costs of the 2020 Revenue Requirements application.

Response:

FBC expects to file its filing to set 2020 rates and will update its forecast application costs in that filing.

H. ACCOUNTING MATTERS AND EXOGENOUS ITEMS

29.0 Reference: EXOGENOUS ITEMS

Exhibit B-2, Application, Sections 6.3.4, 7.2.2 and 12.2.3, pp. 47, 49, 55, 106–107

Mandatory Reliability Standards (MRS)

On pages 106 and 107 of the Application, FBC states the following related to complying with changes to BC's MRS program:

> For 2019, the incremental MRS costs that qualify for exogenous factor treatment are forecast to be $3.720 million, comprised of $0.940 million in incremental O&M expense and an incremental $2.780 million in capital expenditures. These costs continue to exceed the Commission-defined materiality threshold of $0.301 million.

On page 47 of the Application, FBC shows a breakdown of the forecast $0.940 million in incremental O&M expenses in Table 6-6:

Table 6-6: MRS Incremental O&M Expense ($ millions)

Line No.	Description	Approved 2018	Projected 2018	Forecast 2019
1	Assessment Report No. 8	$ 0.540	$ 0.540	$ 0.540
2	Assessment Report No. 10	0.180	0.150	0.400
3	2018 Compliance Audit	0.350	0.350	-
4	Forecast O&M	$ 1.070	$ 1.040	$ 0.940

FBC states on page 49 of the Application that the incremental O&M expenditures associated with Assessment Report No. 10 "are primarily for resource additions in System Operations that will be required to ensure full compliance with October 1, 2020."

On page 55 of the Application, FBC provides a breakdown of the forecast $2.780 million in incremental capital expenditure in 2019 into one-time capital for Assessment Report No. 10 of $2.700 million and sustainment capital for Assessment Report No. 8 of $0.080 million).

29.1 Please provide a list of the individual adopted standards, including a description of the scope of work and individual cost estimate (one-time and ongoing) for the standard, as it relates to the following 2019 cost estimates:

a) $0.540 million incremental O&M for Assessment Report No. 8;

b) $0.400 million incremental O&M for Assessment Report No. 10;

c) $0.080 million incremental capital for Assessment Report No.8; and

d) $2.780 million incremental capital for Assessment Report No. 10

Response:

BCUC Order R-38-15 provides a list of the adopted standards for Assessment Report 8. Of those standards, the suite of CIP v5 standards (total of 10) and PER-005-2 (Operations Personnel Training) attribute to the incremental ongoing O&M and capital costs for AR8. There are no one-time costs in 2019 for AR8.

Standard	Tasks	O&M Cost
CIP-002-5.1 CIP-003-5 CIP-004-5.1 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1	Support the installed systems and tasks which include ongoing efforts to maintain processes and systems that ensure and address physical and cyber security controls, continuous monitoring, change management, patch management and vulnerability assessments. The effort is primarily labour and annual software/hardware licensing fees.	$520,000
PER-005-2	Maintain and continue to deliver required training to support personnel for system operations and control.	$ 20,000
Standard	**Tasks**	**Capital Cost**
CIP-002-5.1 CIP-003-5 CIP-004-5.1 CIP-005-5 CIP-006-5 CIP-007-5 CIP-008-5 CIP-009-5 CIP-010-1 CIP-011-1	Support of the infrastructure that was required for CIP v5 such as annual software upgrades for maintaining support and avoiding potential security, productivity and reliability issues. Also includes leveraging new functionality and features available that the vendors have developed through continued investment in their products.	$ 80,000

BCUC Order R-39-17 provides a list of the adopted standards for Assessment Report 10. Of those standards, three were identified that require significant effort. FBC reviewed the standards as a group as some tasks and tools are similar to achieve compliance. These standards are:

- IRO-017-1 Outage Co-ordination
- TOP-001-3 Real Time Contingency Analysis
- TOP-002-4 Next-Day Operational Planning Analysis

FBC is continuing to develop the scope and select the tools and support systems required. Based on the evaluation to date, the 2019 estimates for AR10 are one-time costs and are as follows.

Standards	Tasks	Operating Cost
IRO-017-1, TOP-001-3 & TOP-002-4	Qualified and trained personnel required in System Operations group (system control centre) to support the new standards coming into effect by October 1, 2020. This would include continuously performing real-time pre- and post-contingency assessments every 30 minutes, meeting outage coordination requirements, and implementing outage scheduling timelines and next day studies as well as obtaining training equivalent to a System Operator. Training for these tasks typically takes approximately 12 to 18 months.	$400,000
Standards	**Tasks**	**Capital Cost[3]**
IRO-017-1, TOP-001-3 & TOP-002-4	Purchase and install the necessary hardware and software systems (including backup) and resources to meet the requirements. This includes Real Time Contingency Analysis (RTCA) software, outage coordination tool to comply with RC processes, operational planning analysis and (daily) assessments. The infrastructure will be required to be within the boundaries of and integrated with the SCADA network.	$2,700,000

29.2 Please explain what is meant by “resource additions in System Operations” (e.g. technology assets, employee additions, other) for the incremental O&M expenditures associated with Assessment Report No. 10.

Response:

The above refers to adding qualified and trained personnel in the System Operations group (system control centre) to support the new standards coming into effect by October 1, 2020. The costs associated are primarily labour and training.

29.3 Please provide a list of any MRS in Assessment Report No. 8 and No. 10 held in abeyance, including its justification, respective risk(s) to the electric system, mitigating solutions and associated cost.

[3] FBC notes the question has a typographical error, where the amount shown as $2.780 million in item d) should instead by $2.700 million.

Response:

Standards that have been held in abeyance have generally been standards applicable to the Planning Authority/Planning Coordinator (PA/PC) function, with the exception of CIP-003-6 in Assessment Report 10. Until such time that the PA/PC function responsibilities are clarified for the Province, these standards cannot be assessed. Commission Order R-41-13 stated that PA/PC responsibilities for the Province require clarification and standards that apply to PA/PCs have been held in abeyance since then.

AR8 Standards held in abeyance include:

- MOD-032-1Data for Power System Modeling and Analysis;
- MOD-033-1 Steady-State and Dynamic System Model Validation; and
- PRC-023-3 Transmission Relay Loadability.

AR10 Standards held in abeyance include:

- PRC-023-4 Transmission Relay Loadability
- PRC-026-1Protection Coordination/Loadability
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- CIP-003-6 Cyber Security — Security Management Controls

FBC had also recommended that CIP-003-6 standard be held in abeyance. The next revision of this standard (CIP-003-7(i)) is in the final stages of approval. FBC recommended this version of the standard be held in abeyance or have an effective date to align with CIP-003-7(i) implementation to avoid potential stranded costs.

Additional standards that pertain to the PA/PC function from Assessment Reports 7 and 9 include:

- EOP-003-2 Load Shedding Plans
- FAC-013-2 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon
- PRC-006-2 Automatic Underfrequency Load Shedding
- PRC-010-2 Under Voltage Load Shedding

Note that FBC is unable to evaluate the risk(s) to the electric system, mitigating solutions and associated costs as it has not historically been the PA/PC entity responsible for the standards held in abeyance.

30.0 Reference: EXOGENOUS ITEMS

Exhibit B-2, Application, Section 12.2, pp. 104–107

Exogenous (Z) factors

On pages 104 to 105 of the Application, FBC describes the Employer Health Tax (EHT) announced as part of the provincial government's budget in February 2018, which will come in effect on January 1, 2018. FBC states that EHT costs are estimated at $1.2 million in 2019 ($0.576 million in O&M and $0.624 million in capital).

On page 106 of the Application, FBC states on December 27, 2017, the provincial government announced the reduction of MSP premiums by 50 percent, effective January 1, 2018, and the elimination of MSP premiums by January 1, 2020. FBC states MSP savings are forecast at $0.350 million in 2018 and 2019 ($0.168 million in O&M and $0.182 million in capital in each year).

30.1 Please explain FBC's methodology for estimating the 2019 forecast for EHT costs and MSP premiums reductions.

Response:

The EHT is an employer-paid payroll tax based on the remuneration to employees. The tax is calculated based on a remittance rate of 1.95 percent of the remuneration.

To estimate the EHT for 2019, FBC started with the actual 2017 employee remuneration ($59.8 million) and applied an annual inflation factor of 2.5 percent for each of 2018 and 2019 to arrive at the forecast remuneration for 2019. The tax of 1.95 percent was then applied to the 2019 forecast remuneration ($62.8 million) to arrive at the $1.2 million estimated EHT for 2019.

The MSP reduction in 2019 is equal to the estimate of MSP to be paid in 2018 (since no MSP would be paid in 2019). To estimate the MSP to be paid in 2018 FBC doubled its MSP costs for the first half of 2018 to represent a full year.

Any variance from forecast for these items will be returned to or recovered from customers by way of the Flow-thru deferral account.

Further, FBC states on page 106 of the Application that incremental MRS costs for 2019 that qualify for exogenous factor treatment are forecast to be $3.720 million ($0.940 million in O&M and $2.720 million in capital).

30.2 Please explain the method of allocating costs/savings between O&M and capital for the following and how it was determined to be appropriate:

- EHT costs
- MSP premium reduction
- Incremental MRS costs

Response:

The EHT costs and MSP premium reduction are included in O&M and capital similar to how OPEB and pension expenses are included. The amounts follow the expected labour allocation between O&M and capital, which is approximately 48 percent and 52 percent, respectively. Just like the OPEB and pension expenses, the EHT costs (starting in 2019) and MSP premiums are included in FBC's labour loadings, and therefore the allocation between O&M and capital, along with other labour loadings, is based on where the labour is expected to be charged.

The incremental MRS costs are included in O&M and capital based on FBC's capitalization policy. FBC capitalizes costs in accordance with generally accepted accounting principles; the determination as to whether costs are capitalized or expensed depends on the nature of the expenditure. MRS costs related to investing in hardware and software, as well as infrastructure additions, were included in capital in order to achieve requirements in the standards.

31.0 Reference: EMERGING US GAAP ACCOUNTING GUIDANCE

Exhibit B-2, Application, Section 12.3.1.2, pp. 108–110

Cloud computing

FBC states on page 108 of the Application that Accounting Standards Update 2015-05 (ASU 2015-15) was issued in 2015, relating to the accounting treatment for cloud computing arrangements. Based on ASU 2015-05, "if a cloud computing arrangement does not meet the criteria of 'having a software licence'… the entity procuring the cloud service should account for the arrangement as a service contract, which would generally mean expensing such costs."

31.1 Please confirm, or explain otherwise, that FBC currently applies ASU 2015-15 as it relates to accounting for cloud computing arrangements.

Response:

FBC will be applying ASU 2018-15 which was finalized on August 29, 2018 and permits the capitalization of cloud computing vendor implementation costs beginning in 2018 as per the transitional provisions of the standard.

FBC first began utilizing cloud computing service in 2009 when it implemented the Fleet Complete Automated Vehicle Locate (AVL) system, which was a hosted solution. However, the implementation of this project occurred before Accounting Standards Update (ASU) 2015-05 Intangibles – Goodwill and Other – Internal – Use Software – Cloud Computing Arrangements which became effective in 2015. Additionally, ASU 2015-05 was applied prospectively (i.e. was not applied retrospectively to existing systems), as permitted in the transition provisions of the standard, and therefore had no effect on the costs associated with the legacy AVL hosted project.

Since ASU 2015-05 became effective in 2015, there have been two cloud computing solutions, of which approximately $170 thousand of vendor implementation costs is estimated to not meet the capitalization criteria set out in ASU 2015-05. These cloud computing solutions were employee facing applications which were shared with FEI and as such the capital costs were allocated to each of FEI and FBC based on the number of employees per company. FBC is in the process of implementing these two cloud computing solutions during 2018. FBC requested Commission approval for variance from GAAP for regulatory purposes to allow for treatment of the vendor implementation costs consistent with FBC's traditional on-premise software.

However, Accounting Standards Update (ASU) No. 2018-15 *(Subtopic 350-40) Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is A Service Contract,* was recently issued on August 29, 2018. The transitional provisions of ASU No. 2018-15 permit FBC to adopt the new guidance to support capitalization of cloud computing

vendor implementation costs beginning in 2018 in accordance with generally accepted accounting principles.

Due to these recent developments in accounting guidance, FBC expects to capitalize $170 thousand of vendor implementation costs associated with cloud computing solutions within the PBR capital formula, rather than being expensed, during 2018. As such, it is no longer necessary for FBC to request a variance from GAAP, as originally outlined in 12.3.1.2 in Section 12 of the Annual Review for 2019 Rates.

31.1.1 If confirmed, please reconcile this to the statement made on page 110 of the Application, which states: "The proposed approach would avoid a one-year change in capitalization policies and the associated potential volatility in O&M and capital" [emphasis added] given that the current proceeding is to set rates for 2019.

Response:

At the time of filing FBC's Annual Review for 2019 Rates, the outcome of the final ASU 2018-15, including the transitional provisions on when it could be applied, was not certain. If ASU 2018-15 only permitted capitalization of such costs beginning in 2020 on a prospective basis and FBC did not receive regulatory approval to capitalize vendor implementation costs on cloud computing arrangements, such costs would be expected to be expensed pursuant to ASU 2015-05. This would then result in a "one-year change in capitalization policies and the associated potential volatility in O&M and capital" associated with cloud computing vendor implementation costs under ASU 2015-05 until such time that ASU 2018-15, which permitted such capitalization of such costs, became effective. However, ASU 2018-15 was recently issued and finalized on August 29, 2018 and the transitional provisions permit FBC to capitalize cloud computing vendor implementation costs beginning in 2018 in accordance with generally accepted accounting principles.

31.2 Please clarify whether expensing cloud computing implementation costs has been an issue in previous years of the PBR term.

Response:

The regulatory accounting treatment of cloud computing vendor implementation costs has not been an issue during the term of the PBR plan as cloud computing was not a prevalent Information System when the PBR plan was first established. The base capital formula established at the beginning of the PBR term included traditional on-premise software and did not forecast cloud computing solutions with vendor implementation costs. The base O&M formula also did not include any cloud computing implementation costs.

31.2.1 If yes, please explain how FBC addressed the treatment of these costs in the past, and why it is not able to treat this issue in the same manner it has been dealt with in previous years.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.2.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.31.1.

FBC states on page 110 that "The proposed approach keeps FBC's O&M and capital funding envelopes consistent with the 2013 Base O&M and capital amounts for the final year of the PBR term, which were based on the assumption that IS [Information Systems] implementation costs would be capitalized."

31.3 Please provide the amount of IS implementation costs for cloud computing solutions which was assumed in setting FBC's base O&M and capital amounts for the PBR term.

Response:

Please refer to the response to BCUC IR 1.31.2.

31.4 Please provide the actual 2015 to 2017 and projected/forecast 2018 number of cloud computing solutions and total IS implementation costs incurred by FBC (O&M and capital). If any cloud computing services are shared between FBC and FEI, please separately identify these and discuss also the cost allocation methodology.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.5 Please quantify the cloud computing implementation costs that FBC expects to recognize as capital expenditures for 2019 in the event it is approved to vary from US GAAP for 2019.

Response:

At this time, there is only one cloud computing project that is expected to occur in 2019 of which approximately $85 thousand represents vendor implementation costs. There are likely other cloud computing solutions that could be considered during 2019; however, as described in section 12.3.1.2 of the Application, “the form in which the solution is offered, either through traditional on-premise software or through cloud computing, is not known until discussions occur with the external vendor.” Accordingly, the amount of vendor implementation costs for cloud computing solutions in 2019, other than the $85 thousand noted above which will be included in the 2019 formulaic capital expenditures, is not known at this time. As a result of the final ASU 2018-15 being issued on August 29, 2018, the transition provisions permit FBC to capitalize such costs under generally accepted accounting principles.

31.5.1 As part of the above response, please estimate the impact that the change in capitalization policies would have on O&M and capital in 2019 if FBC's request to vary from US Generally Accepted Accounting Principles (GAAP) in 2019 was not approved.

Response:

Please refer to the response to BCUC IR 1.31.5.

On page 109 of the Application, FBC states the following:

> In June 2018, the Financial Accounting Standards Board (FASB) agreed to issue a final ASU in the third quarter of 2018 based on the March 1, 2018 issuance of the *Exposure Draft: Proposed ASU (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is A Service Contract.* The primary consensus reached for the new ASU is that the capitalization of implementation costs incurred for a cloud computing arrangement that is a service contract is consistent with the capitalization of implementation costs incurred to develop or obtain on-premise software and hardware… While the new ASU 350-40 supports the capitalization of initial external vendor cloud computing implementation costs and can be applied retroactively, it is not expected to become effective until [January 1,] 2020.

31.6 Please provide the transitional guidance issued by FASB with respect to retroactive adoption of the new ASU 350-40, and explain whether FBC's proposal for a one-year variance from US GAAP for 2019 is consistent with that guidance.

Response:

The transitional provisions for ASU 2018-15, shown below, permit FBC to capitalize cloud computing vendor implementation costs effective 2018 and onwards.

> **Transition and Open Effective Date Information**
>
> **> Transition Related to Accounting Standards Update No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract***

350-40-65-3 The following represents the transition and effective date information related to Accounting Standards Update No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*:

a. For **public business entities**, the pending content that links to this paragraph shall be effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2019.

b. For all other entities, the pending content that links to this paragraph shall be effective for annual periods beginning after December 15, 2020, and interim periods in annual periods beginning after December 15, 2021.

c. Earlier application of the pending content that links to this paragraph is permitted, including adoption in any interim period for:

    1. Public business entities for periods for which financial statements have not yet been issued

    2. All other entities for periods for which financial statements have not yet been made available for issuance.

d. An entity shall apply the pending content that links to this paragraph using one of the following two methods:

    1. Prospectively to costs for activities performed on or after the date that the entity first applies the pending content that links to this paragraph

    2. Retrospectively in accordance with the guidance on accounting changes in paragraphs 250-10-45-5 through 45-10.

e. A public business entity that elects prospective transition shall disclose the following in the interim and annual periods of adoption:

    1. The nature of and reason for the change in accounting principle

    2. The transition method

    3. A qualitative description of the financial statement line items affected by the change.

f. A public business entity that elects retrospective transition shall disclose the following in the interim and annual periods of adoption:

    1. The nature of and reason for the change in accounting principle

    2. The transition method

    3. A qualitative description of the financial statement line items affected by the change

4. Quantitative information about the effects of the change.

g. All other entities shall disclose the information in (e) or (f) for prospective transition or retrospective transition, respectively, in the annual period of adoption, unless the entity elects to early adopt the pending content that links to this paragraph in an interim period, in which case the entity also shall disclose that information in the interim period of adoption.

31.7 In the event that the FBC proposal for a one-year variance from US GAAP for 2019 for the cloud computing costs is not approved, please provide the impact on the revenue requirement and rates, and forecast O&M and capital spending.

Response:

Please refer to the responses to BCUC IRs 1.31.1 and 1.31.5.

31.8 Please explain how FBC would apply retroactive adoption of the new standard (if at all) under a scenario where: (i) FBC is approved to vary from US GAAP for 2019; and ii) FBC is not approved to vary from US GAAP for 2019. Please quantify the impact of applying ASU 350-40 retroactively in each scenario, both from a cost perspective and a rate impact perspective.

Response:

In addition to the following response, please refer to the response to BCUC IR 1.31.1.

In a hypothetical situation where a finalized ASU 2018-15 was not issued on August 29, 2018, and FBC were approved for its initial request of a variance from USGAAP ASU 2015-05 in order to capitalize cloud computing vendor implementation costs, this treatment would be permitted under USGAAP pursuant to ASC 980 Rate-Regulated Operations. As a result, no retroactive adoption of the new standard would be required.

Conversely, in a hypothetical situation where a finalized ASU 2018-15 was not issued on August 29, 2018, and FBC were not approved for its initial request for a variance USGAAP ASU 2015-05, FBC would expense the vendor implementation costs. If the standard were applied in 2020 with retroactive application, FBC would have to consider whether a retroactive application was feasible or desirable, based on the timing of the standard in relation to FBC's rate filing with the

Commission, the impact, and any other relevant factors at the time. As ASU 2018-15 was, in fact, issued on August 29, 2018, FBC has not sought to quantify the impact of applying ASU 350-40 retroactively in this hypothetical scenario.

31.9 Please discuss the likelihood that ASU 350-40 will come into effect on January 1, 2020.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.9.1 In the event that the new ASU 350-40 does not come into effect on January 1, 2020 or there is a material change between the Exposure Draft and the final new ASU 350-40, how does FBC propose to address this delay or change?

Response:

Please refer to the response to BCUC IR 1.31.1.

31.10 Please confirm, or explain otherwise, that FBC's practice is generally not to request regulatory approval for changes related to proposed accounting or government-related changes (e.g. income tax rates) until the change has been made effective or enacted.

Response:

FBC agrees that it does not generally request approval for income tax rate changes until they have been enacted. Income tax rate changes, and many other legislated changes, have to go through a separate process for implementation after they have been announced, and there can be changes to these announcements before the final enactment. However, FBC may still

discuss treatment options in its filings in advance of the government finalizing changes where there is value to be gained from exploring options with the Commission and interveners.

For proposed accounting changes, the timing of requesting approval will often depend on the timing of applications that FBC is filing, the term that is covered by the application(s), and the implementation options for the accounting changes. Under the current PBR, FBC is required to bring forward accounting changes as part of the annual review process, which provides some opportunity to wait for accounting changes to be finalized before proposing adoption. Certain accounting standards may have transitional provisions that permit the guidance to be applied retroactively or early adopted. Other than the cloud computing accounting guidance, there have not been any recent accounting standards where FBC has intended to early adopt or retrospectively apply for rate setting purposes.

31.10.1 As part of the above response, please provide examples where FBC has requested approval from the BCUC to change its application of accounting standards or government policies in advance of the standard/policy being made effective/enacted the BCUC's decision.

Response:

While FBC has not recently requested such changes in advance, Commission Order G-141-09 approved FEI to prepare its 2010 and 2011 Revenue Requirements based on the International Accounting Standards Board (IASB) Exposure Draft on rate regulated activities, which supported the recognition of regulatory assets and liabilities. This approval was based on an Exposure Draft but prior to the issuance of the final International Financial Reporting Standard for rate regulated activities. If there was a difference between the Exposure Draft and the final standard, FEI was directed to apply to the Commission to seek changes in regulatory treatment. Additionally, Commission Order G-6-04 approved FBC's request for a variance from GAAP to treat the lease obligation for the Brilliant Terminal Station agreement as an operating lease rather than as a capital lease for regulatory purposes.

32.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.1.2, p. 114

Rate Design and Rate for Electric Vehicle Direct Current Fast Charging Service Application

On page 114 of the Application, FBC describes the proposed Electric Vehicle Charging Stations Rate Design and Tariff Application deferral account.

32.1 Please discuss why a short term interest (STI) return, as opposed to weighted average cost of debt (WACD) return, is proposed for the Electric Vehicle Charging Stations Rate Design and Tariff Application deferral account.

Response:

FBC should have requested a WACD rate of return. Since the deferral account is not being amortized at this time, a WACD rate of return is consistent with the treatment of FBC's other multi-year deferral accounts. FBC will reflect this change in Schedules 12 and 12.1 in its Evidentiary Update.

32.2 Please provide a breakdown of the forecast $0.060 million additions to the above-noted deferral account between cost which have been incurred to-date and expected future costs when the proceeding resumes.

Response:

FBC's current forecast of the costs for this application is provided below. At this time FBC does not know the scope of the regulatory review of this application, which was adjourned pending the conclusion of the BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, and has assumed that the scope will be limited.

	Spent	Forecast	Total
		($ millions)	
Commission and Intervener Costs	-	$ 0.040	$ 0.040
Legal Fees	0.015	0.005	0.020
Consulting Fees	-	-	-
Other External Costs	-	-	-
	$ 0.015	$ 0.045	$ 0.060

32.2.1 Please confirm, or explain otherwise, whether the after-tax forecast additions to the above-noted deferral account are intended to be $0.044 million as opposed to $0.44 million as shown on page 114 of the Application.

Response:

Confirmed. The after-tax amount is $0.044 million.

33.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.1.3, p. 114

BC Hydro Waneta 2017 Transaction

On page 114 of the Application, FBC describes the proposed BC Hydro Waneta 2017 Transaction deferral account and states that it incurred external legal costs of $0.124 million for its participation in this proceeding. FBC seeks "approval of a deferral account attracting a STI return to capture the costs of participation and proposes to amortize the costs over one year, in 2019."

33.1 Please explain the purpose of FBC's participation in the BC Hydro Waneta 2017 Transaction proceeding.

Response:

FBC participated in the BC Hydro Waneta 2017 Transaction proceeding in order to ensure that the interests of FBC's customers were considered during the proceeding.

As explained in FBC's Final Argument,[4] FBC believes that since FBC is a direct customer of BC Hydro that FBC ratepayers will participate in the benefits that BC Hydro is expected to realize from the Waneta 2017 Transaction.

In addition, given the changes to the system that FBC shares with Teck, there were several technical matters that required discussion and agreement that were relevant to the proceedings. These resulted in letter agreements with both Teck[5] and BC Hydro[6]. As submitted in FBC's Final Argument, these letter agreements provide stability and certainty in terms of FBC's access to Line 71 during the term of the Lease. Line 71 is used to purchase cost effective market power. Ensuring continued access to Line 71 during the term of the Lease was therefore important to ensure FBC continues to have access to market resources.

33.2 Please discuss whether FBC considered making an application for Participant Assistance/Cost Awards (PACA) for its participation in the BC Hydro Waneta 2017 Transaction, and if so, why an application for PACA was not chosen in favour of FBC's current proposal.

4 http://www.bcuc.com/Documents/Arguments/2018/DOC_51599_05-17-2018-FBC-FinalArgument.pdf.
5 http://www.bcuc.com/Documents/Proceedings/2018/DOC_50817_C1-10_FBC-Teck-Agreement-Executed.pdf.
6 http://www.bcuc.com/Documents/Proceedings/2018/DOC_50819_B-17_BCH_FBC_Agreement.pdf.

Response:

FBC did not consider making a PACA application for its participation in the BC Hydro Waneta proceeding. The PACA Guidelines in effect prior to August 31, 2016, had the provision that, except in limited circumstances, eligibility for PACA was limited to "ratepayer" groups. That provision established the historical practice of utilities being expected to fund their active participation in other utilities' proceedings as part of their cost of service being recovered from their own ratepayers. The current PACA Guidelines[7] no longer include this eligibility provision; however, FBC and the other FortisBC utilities[8] (the FBCU) continue to observe this long-standing principle and practice. The FBCU have never made a PACA claim against BC Hydro or any other utility (irrespective of utility size) for costs related to interventions into other utility proceedings. When the FBCU actively intervene in other utility processes, it is because of a direct interest in an issue or issues which have the potential to impact the operation of the utility and the utility's respective customers/ratepayers. FBC is of the understanding that each utility is to fund its own interventions on behalf of its customers. As such, FBC believed it was not appropriate to make a PACA application under these circumstances.

33.3 Please discuss why an amortization period of one year is appropriate for the BC Hydro Waneta 2017 Transaction deferral account.

Response:

When determining an amortization period for deferral accounts, FBC takes into account the relationship between the recovery period and the benefits of the expenditure, the impact on rate stability, and the goal of disposing of the deferral account expeditiously. As identified in the response to BCUC IR 1.33.1, there are ongoing benefits to FBC's participation in this proceeding; however, given the size of the deferral account, matching the amortization to the benefit period would result in small annual amounts. FBC therefore believes that it is more reasonable to fully amortize the account in one year.

[7] Approved by Order G-97-17 dated June 15, 2017.
[8] FortisBC Energy Inc. and FortisBC Alternative Energy Inc.

34.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.1, pp. 114–115

2018-2019 Revenue Surplus deferral account

On page 115 of the Application, FBC seeks approval to "add the forecast 2019 revenue surplus to the 2018 Revenue Deficiency [deferral] account and rename the account the 2018-2019 Revenue Surplus account."

34.1 In the event that the request is not approved, please provide the impact on 2019 rates (i.e. if the 2018 revenue deficiency was amortized in 2019 rates and the 2019 projected revenue surplus was recorded in separate deferral account for disposition in a future year).

Response:

Amortizing the 2018 revenue deficiency in 2019 would result in a rate increase of 0.24 percent for 2019.

35.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.2, pp. 111, 115

2019-2022 DSM Expenditures application

On page 115 of the Application, FBC states that it proposes to amortize the 2019-2022 DSM Expenditures application deferral account over "a four-year period beginning in 2019 which is the term to be covered by the expenditure schedule."

On page 111 of the Application, FBC explains that the proposed term of each regulatory proceeding cost deferral account "encompasses the preparation and filing of the relevant regulatory application and its review by the Commission."

35.1 Please reconcile the difference between the two statements noted in the preamble above. As part of the response, please provide FBC's rationale for why a four-year amortization period which is based on the term to be covered by the expenditure schedule is appropriate as opposed to another amortization period which is based on the preparation and filing of the 2019-2022 DSM Expenditures Application (as stated on page 111 of the Application).

Response:

The statement on page 115 refers to the four-year period to which the 2019-2022 DSM Expenditure Schedule will apply and to the proposed amortization period. The statement on page 111 refers to the period for which the deferral accounts themselves are approved for (the period of time during which FBC expects to add costs to the deferral accounts), which includes both the application preparation time and the application review time.

Regarding the second question and given the clarification provided above, it would not be appropriate to amortize a deferral account over the period of time that there are costs being incurred: first because FBC does not know the balance in the deferral account at that time, and second because there is no link between the time period an application is being developed over (which can span years prior to filing) and the benefits associated with that time period. FBC believes there should be a causal relationship between the recovery period and the benefits associated with the expenditure, and that it is generally most reasonable, and is accepted regulatory practice, for the recovery term of regulatory application cost deferral accounts to align with the term over which the decisions apply. This is consistent with the principle that the amortization period for a deferral account should consider the timing of associated benefits.

36.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.3, pp. 111, 115–116; FBC Annual Review for 2016 Rates (2016 Annual Review), Exhibit B-1, p. 104

2017 Cost of Service Analysis (COSA) and Rate Design Application (RDA)

On page 115 of the Application, FBC states that Order G-202-15 (relating to the 2016 Annual Review) approved the creation of a deferral account to capture the external costs for the preparation and review of its COSA/RDA. The expected cost of that proceeding is $1.520 million ($1.110 million after tax) which FBC proposes to amortize over a five-year period beginning in 2019, stating "this amortization period is consistent with that generally used for rate design applications by FBC and consistent with the anticipated time between filing a COSA and RDA.

On page 104 of the 2016 Annual Review application, FBC stated that it expects the balance in the 2017 RDA deferral account to range between $0.600 and $0.700 million.

36.1 Please explain in detail the causes/factors which resulted in FBC revising the estimated balance in the 2017 RDA deferral account to be $0.920 million to $0.820 million higher than what was projected in the 2016 Annual Review application.

Response:

FBC does not have a breakdown of the components of the initial 2016 forecast of proceeding costs.

When reviewing the forecast in preparation for its Annual Review for 2018 Rates, FBC considered that the original forecast should be revised in light of the actuals incurred in the review of its last RDA, and increased the forecast to $1.9 million (pre-tax). At this time, FBC is reducing the forecast RDA proceeding costs to $1.120 million, based on lower expert consulting and legal expenses incurred to date. This revision is included in the Evidentiary Update filed on September 25, 2018.

The table below shows the actual costs of the 2009 RDA review compared to the forecast costs of the 2017 RDA as presented in the Annual Review for 2018 Rates and as currently forecast.

	2009 RDA Actual	2017 RDA Forecast	
		2018 AR	2019 AR
	($ millions)		
Commission and Intervener Costs	$ 0.562	$ 0.600	$ 0.600
Legal Fees	0.579	0.500	0.200
Consulting Fees	0.768	0.750	0.300
Other External Costs	0.042	0.050	0.020
	$ 1.951	$ 1.900	$ 1.120

FBC has based this current estimate on the expectation of the COSA/RDA proceeding being concluded by way of a written hearing but notes that the process for completion of the proceeding has not yet been determined. The proceeding still includes the potential for an oral hearing component, which is not accounted for in this estimate.

36.2 Please provide a breakdown of the $1.520 million in expected costs related to the 2017 COSA/RDA by cost category.

Response:

Please refer to the response to BCUC IR 1.36.1.

On page 111 of the Application, FBC explains that the proposed term of each regulatory proceeding cost deferral account "encompasses the preparation and filing of the relevant regulatory application and its review by the Commission."

36.3 Please provide FBC's rationale for why a five-year amortization period based on the anticipated time between filing a COSA and RDA is appropriate as opposed to another amortization period which is based on the preparation and filing of the 2017 COSA and RDA (as stated on page 111 of the Application).

Response:

Please refer to the response to BCUC IR 1.35.1.

37.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Application, Section 12.4.2.5, p. 117–119

Flow-through deferral account

On page 117 of the Application, FBC states "it has also included an adjustment for the difference between the projected ending 2017 deferral account credit balance of $7.102 million embedded in 2018 rates and the actual ending 2017 deferral account credit balance of $9.356 million, a credit difference of $2.254 million." This is shown on line 30 of Table 12-4 on page 118 of the Application.

On page 119 of the Application, FBC states that the true-up of $2.254 million is "primarily the net result of higher sales revenue net of power purchase expense due to weather-related increases in load, in addition to higher savings on market purchases of power."

37.1 Please provide a table in the same format as Table 12-4, to show the breakdown of the projected ending 2017 deferral account balance of $7.102 million and actual ending 2017 deferral account balance of $9.356 million in order to explain true-up amount of $(2.254) million.

Response:

The true-up amount to the 2017 Flow-through deferral account additions is detailed in the table below.

Line No.	Description	Approved	Actual	Variance	Projected Variance	Change in Variance
1	Revenue	$ (362.128)	$ (364.854)	$ (2.726)	$ 1.736	$ (4.462)
2						
3	Power Purchase Expense	136.216	133.214	(3.002)	(5.779)	2.777
4						
5	Wheeling	4.928	5.124	0.196	0.089	0.107
6						
7	Water Fees	10.328	10.316	(0.012)	0.001	(0.013)
8						
9	O&M Tracked Outside of Formula					
10	Insurance Premiums	1.327	1.268	(0.059)	(0.060)	0.001
11	Advanced Metering Infrastructure Project	(1.126)	(1.246)	(0.120)	-	(0.120)
12	Mandatory Reliability Standards Incremental O&M	0.050	0.053	0.003	-	0.003
13	Upper Bonnington Unit 3 Annual Inspection	(0.040)	(0.040)	-	-	-
14						
15	Property Tax	16.052	15.723	(0.329)	(0.164)	(0.165)
16						
17	Depreciation and Amortization	55.657	55.618	(0.039)	0.062	(0.101)
18						
19	Other Revenue	(8.056)	(9.724)	(1.668)	(0.924)	(0.744)
20						
21	Interest Expense	40.191	38.127	(2.064)	(1.739)	(0.325)
22						
23	Income Tax	10.849	12.201	1.352	1.455	(0.103)
24						
25	Working Capital Adjustment for AMI - booked in 2018		-		(0.006)	0.006
26						
27	Duplication of 2016 Flow-Through True-Up				(0.886)	0.886
28						
29	2018 After-Tax Flow-Through Addition to Deferral Account			(8.470)	(6.215)	(2.254)

37.1.1 Please provide an explanation for any significant variances identified in the table provided in response to IR No. 37.1 above.

Response:

The variance in revenue between the projected ending 2017 Flow-Through deferral account balance embedded in 2018 rates and the actual ending 2017 deferral account balance is primarily the net result of higher sales revenue net of power purchase expense due to weather-related increases in load, in addition to higher savings on market purchases of power.

The increase in Other Revenue is due to higher than forecast pole attachment revenue as a result of issuing final invoices in the last half of the year, higher connection charges resulting from customer growth, and higher than forecast other recoveries from construction work for a third party.

Interest expense was lower than projected mainly due to the later than projected issuance of $75 million in long term debt.

FBC inadvertently duplicated the true-up of the 2016 Flow-through account in the deferred charges schedule for 2018 rates[9] and is correcting this error through the true-up of the 2017 Flow-through account, at Line 27 in the table in response to BCUC IR 1.37.1.

[9] In its response to BCUC IR 1.23.1 in Annual Review for 2018 rates, Line 5 of Schedule 12 showed 2017 gross additions to the Flow-through deferral account of $(6.215) million, which was comprised of the projected 2017 Flow-through amount of $(5.329) million plus the 2016 Flow-through true-up of $(0.886) million (Table 12-5 in the Annual Review for 2018 Rates). The addition of the 2016 true-up to the deferral account for rate setting was an error, because the opening balance of the account was based on year-end actuals as filed in FBC's 2016 Annual Report to the BCUC, and already included the true-up amount of $(0.886) million.

I. SERVICE QUALITY INDICATORS

38.0 Reference: SERVICE QUALITY INDICATORS
Exhibit B-2, Application, Section 13.2.1, p. 123
All Injury Frequency Rate (AIFR)

On page 123 of the Application, FBC provides information related to the AIFR for 2017 and 2018 year-to-date (YTD) and states;

> The June 30, 2018 YTD AIFR is 2.56. As of June 30, 2018, there were 2 Medical Treatment and 4 Lost Time injuries. Four of these six events occurred in January. If the recent improving trend in performance continues, FBC expects the 2018 AIFR to improve over the course of the year.

38.1 Please provide further information regarding the four safety events which occurred in January. How were these safety events related in terms of work site or scope of work and what actions has FBC undertaken to mitigate similar safety risks in the future?

Response:

Three of the four January safety events occurred during work activities as a result of sudden inclement weather conditions with significant snow fall. Please refer to the table below.

Date	Location	Occupancy	Affiliation	Injury's nature	Preventive/ Corrective actions
1/5/2018	Trail	Customer Service Representative	MoveUP	Overexertion	• Increase work observations and promote regular MoveSafe warm up and stretching breaks. • Employee was advised to immediately seek First Aid • Discuss importance of stretching/ warm up exercises as a part of MoveSafe Program Request OHS department to deliver a presentation focusing on Ergonomic Hazard in Office environment to increase awareness
1/18/2018	South Interior	Crew Leader (PLT)	IBEW	Overexertion	• Discussion about self-awareness, limitations, rushing and communication to form part of the SSWP documentation prior to beginning work. Supervisor to follow-up with crew observations • SSWP group exercise to enhance the employee's ability to identify hazards associated with particular tasks. Review the identified hazards to verify consistency. • Consider the use of snow shoes if the conditions are appropriate for the work to be completed. • Consider the use of the side by side with tracks to pack down a trail.
1/10/2018	Kootenay	Customer Service Person	IBEW	Fall	*Review with Meter department on how update location details and warnings on spreadsheet. Eliminate old codes from CIS. *Ensure updates on new potential hazards are being documented on Meter Reader Spreadsheet and entered into SSWP. Supervisor to follow up on future Crew Visits. *Lessons Learned: Diccussion and review
1/8/2018	Kelowna	Power Line Technician	IBEW	Repetitive motions	• Lessons learned: discussion with employee physical limitations and importance of Warm up performs stretches before doing any physical task to help prevent MSI.• PLT discusses the use of pin finder to reduce the amount of shoveling required to locate hidden facilities underneath the snow. PLT to demonstrate.

38.2 Please explain why FBC expects the 2018 AIFR to improve over the course of the year (e.g. actions undertaken to improve safety, other). Please also discuss FBC's expectations as it relates to achieving the three-year rolling benchmark for the AIFR in 2018.

Response:

FBC continues to emphasize continual improvement in injury and incident reduction through employee engagement with the Occupational Health and Safety team spending additional time in the field with crews, engaging them in safety best practice conversations and at the same time recognizing and sharing proactive safety messages.

The YTD 2018 AIFR has improved since June with August 31 at 1.96 compared to the June 30 results at 2.56, resulting in a three year rolling average of 1.41, which is better than the

1 benchmark. If the recent improving trend in performance continues, FBC expects the 2018
2 AIFR to improve over the remainder of the year.

3

39.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.2, p. 129

Telephone abandon rate

On page 129 of the Application, FBC provides Table 13.10 showing historical telephone abandon rates:

Table 13-10: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Annual Results	2.2%	1.9%	1.7%	1.9%	2.0%	12.4%	2.7%	3.9%	4.7%	5.0%
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

FBC states that it "attributes the increase in the abandon rate in recent years to an increase in customers using the self-serving option through the interactive voice response messages during power outages."

39.1 Please provide support for why FBC attributes the increase in the telephone abandon rate in recent years to customers using the self-serving option through the interactive voice response messages during power outages (e.g. data on self-serving options selected, telephone abandon rates during/after power outages, calls received during/after power outages, etc.).

Response:

FBC is not able to determine with certainty the reasons that a customer abandons a specific call. The abandon rate can vary depending on the frequency and nature of large outages often caused by storms. The increase may also reflect an increase in customers self-serving through the interactive voice response (IVR) messages during power outages and/or an increase in customer-related abandons (hanging up prior to entering a queue). The Abandon Rate would be expected to increase during outage periods to the extent that IVR messages provide the customer with the information about the outage that they are looking for.

As shown in the response to CEC IR 1.32.1, because the average speed of answer has remained relatively consistent and the Telephone Service Factor benchmarks have been met, FBC believes that it is reasonable to largely attribute the increase in Abandon Rate over this period to the use of IVR messages during outages.

39.2 Other than customers using the self-serving option through the interactive voice response messages during power outage, please provide other factors (if any) which may explain the increase in telephone abandon rates since 2015.

Response:

Please refer to the response to BCUC IR 1.39.1.

40.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.3, pp. 121, 130–133

System Average Interruption Duration Index (SAIDI) – Normalized

On page 120 of the Application, FBC states that both 2017 and 2018 year-to-date SAIDI results performed poorer than the threshold, primarily due to the implementation of the OMS, which automated the tracking of outage data. Further, FBC states "the 2017 SAIDI results were impacted by wildfires. Specifically, wildfires in the Princeton and Joe Rich areas of the Okanagan accounted for approximately 78,000 customer hours or 15 percent of the annual SAIDI." For 2018, in addition to the OMS, FBC states the main contributor for higher SAIDI was the reliability of the transmission system due to adverse weather related outages/large snow fall events. Additionally, FBC states "On January 17, [2018] a forestry worker near a transmission line right of way caused an outage that resulted in 27,000 customer hours."

FBC shows the 2009 to 2017 and 2018 year-to-date results in Table 13-11 on page 131 of the Application, as copied below:

Table 13-11: Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	June 2018 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.76	3.26
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62	2.62	2.62

Further, on pages 130 and 131 of the Application, FBC states:

> With the change to the OMS and a different definition to the Outage Start Time, the reported outage times have increased, causing the SAIDI values reported to increase, even though there has been no change in the company's operating practices. FBC estimates the increase in reported values for SAIDI as the result of the OMS to be in the 15 to 30 percent range, consistent with other utilities' experience who has replaced their manual systems with an OMS. As recorded on page 7 of the November 21, 2014 minutes for the SQI [Service Quality Indicator] Workshop, FBC stated that "with AMI [Advanced Metering Infrastructure], the company many need to assess the impact on the SAIDI measure as the company would be notified of outages earlier than previously. [Emphasis added]

FBC also states on page 131, "If SAIDI were normalized for the estimated impact of the OMS, FBC's three-year rolling average SAID results for 2017 would be better than the threshold."

40.1 Please clarify when (i.e. month/year) FBC implemented the OMS.

Response:

The OMS was implemented in January of 2017.

40.2 Please provide SAIDI results for 2017 annual and 2018 year-to-date, which have been normalized for the estimated impact of the OMS, and compare to the benchmark and threshold.

Response:

Reliability results, including SAIDI, are impacted by both the transmission and distribution system reliability. The ADMS project has only impacted the accuracy of the distribution system reporting. From a transmission reliability reporting perspective, FBC's processes have not changed with the introduction of the OMS.

In 2017, both the Transmission and Distribution SAIDI values were considerably higher than in 2015 and 2016 due to an increase in adverse weather, foreign interference (e.g. vehicle accidents), and the impact of forest fires, all of which are outside the control of FBC, in addition to the impact of OMS.

Since OMS was only implemented twenty months ago and during a year impacted by increased weather-related outages, the exact impact on SAIDI cannot be quantified. One area where the OMS likely had a significant impact is in the identification of and accounting for major adverse weather-related outages. Prior to OMS, FBC relied on individual customers to notify the utility of a power outage. During these widespread events impacting both the transmission and distribution systems, call handling and field resources could quickly become backlogged. This led to challenges in fully understanding the scope and scale of system damage and the extent of all the outages on the system. Given the limitations of the previous systems, it would take significantly longer to fully and accurately account for all outages.

Other utilities implementing an ADMS have experienced an impact to SAIDI of approximately 15 percent to 30 percent. FBC does not have any reason to believe that its own experience would fall outside of this range.

40.2.1 Does FBC consider that its SAIDI performance should be assessed on a normalized basis? Please explain why or why not.

Response:

FBC is not proposing that SAIDI performance should be normalized for the effect of OMS as it is difficult to assess what the exact impact has been with a high degree of accuracy. Instead, FBC is explaining why SAIDI performance is higher than the threshold and that the SAIDI performance is appropriate given the circumstances and should not be considered a degradation of service quality.

40.3 Please discuss how the implementation of the OMS and AMI impacts FBC's ability to set a future SAIDI measure.

Response:

FBC does not anticipate any issues in setting a benchmark for SAIDI in the future as part of the next PBR Plan.

For example, with the start of the next PBR Plan expected to be 2020, FBC will have three full years of SAIDI results available (i.e. 2017, 2018 and 2019) incorporating the impact of the OMS. Similar to the current three-year average methodology used today, the proposed benchmark could then be based on the average of the 2017, 2018 and 2019 results.

40.4 Please provide a summary discussion of the causes, if known, of the wildfires in 2017. Specifically, please indicate the number of wildfires caused by (or potentially caused by) downed power lines, if this information is available.

Response:

The Princeton and Joe Rich fires were both believed to have been caused by lightning.

40.5 Please discuss whether wildfires in 2018 are expected to impact 2018 annual SAIDI performance.

Response:

Currently, the 2018 wildfires have not had a significant impact on SAIDI performance. There have been short outages required on both the transmission and distribution system required to support firefighting efforts. The impact to FBC infrastructure has been minimal due to these fires.

40.5.1 If possible, please provide updated 2018 year-to-date SAIDI results at the time of filing this IR response.

Response:

The 2018 YTD SAIDI result as of the end of August is 2.50.

40.6 Please provide the historical number of snowfall events and snowfall-related outages experienced from 2015 to 2018 year-to-date.

Response:

FBC is not able to specifically report on all snowfall related events as the outages are commonly coded to other factors. For example, during a heavy snowstorm there may be widespread outages due to trees contacting power lines from snow loading. This event would be classified as a tree contact in the outage database.

However, FBC can confirm that snow events have been the cause of four major events that qualified for normalization since 2015.

40.7 Given the January 17, 2018 incident, please discuss the measures (if any) which FBC has taken to mitigate similar future events.

Response:

WorkSafe BC has procedures in place to ensure the safety of workers near energized power lines (OHS Regulations Part 19). Had these procedures been followed, it is likely that this event could have been avoided. While FBC does not have direct authority over these third parties, it participated in the event investigation which was led by WorkSafe BC. FBC is not aware of what, if any, corrective measures followed this investigation.

FBC states on page 131 of the Application that 2017 annual SAIDI performance was 4.05.

40.8 Please add an additional row to Table 13-11 on page 131 of the Application, showing FBC's annual historical and 2018 year-to-date SAIDI results.

Response:

The requested version of Table 13-11 is provided below.

Historical SAIDI Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	August 2018 YTD
Three year rolling average results	2.40	2.51	2.33	2.22	1.94	2.09	2.15	2.18	2.76	3.13
Annual result	2.28	2.84	1.86	2.00	2.01	2.32	2.13	2.10	4.05	3.24
Benchmark	n/a	n/a	n/a	n/a	n/a	2.22	2.22	2.22	2.22	2.22
Threshold	n/a	n/a	n/a	n/a	n/a	2.62	2.62	2.62	2.62	2.62

41.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Application, Section 13.2.3, p. 132

Generator Forced Outage Rate (GFOR)

On page 132 of the Application, FBC states

> The 2017 result for GFOR was 0.6 percent and is mainly attributable to equipment failures at Upper Bonnington and Corra Linn plants. The failures included UBO Unit 1 outages caused by governor issues in April and an oil leak in June and an outage on COR Unit 3 on November 17th caused by a Potential Transformer failure.

41.1 Please provide a table explaining the origin/cause, cost and mitigating solutions undertaken by FBC to address the equipment failures (e.g. governor failure, oil leak and potential transformer failures) at Upper Bonnington and Corra Linn plants.

Response:

The table below explains the origin/cause, cost and mitigating solutions undertaken by FBC to address the equipment failures reported on Exhibit B-2, Application, Section 13.2.3, p. 132.

Plant/Unit	Failure Description	Date of failure	Cause of failure	Cost of failure	Mitigation solutions
UBO/Unit 1	Governor mechanical failure	April 3, 2017	Failure of the Unit 1 governor due to normal wear and tear due to its age	$21,666	Governor was temporary repaired with spare parts from the Unit 3 governor, which was replaced in 2017 as part of the UBO Refurbishment project. The Governor on Unit 1 will be replaced in 2019.
UBO/Unit 1	An oil spill was detected on Unit 1 upper guide bearing and the Unit was shut down to contain the oil spill	June 26, 2017	The oil spill was due to the deficient design of the original installation.	-	The guide bearing oil system on all units will be upgraded as part of the UBO Refurbishment project and will be including a system that will alarm when the oil levels could cause an oil spill. The Unit 1 system will be upgraded in 2019.
COR/Unit 3	Potential transformer failure caused Unit 3 protection to trip Unit 3	November 17, 2017	The design of the potential transformer did not include protection against ferro - resonance. When Unit 3 was taken offline, a small instability resulted in a ferro - resonance condition in the bus leading to overvoltage and protection operation.	$26,891	A damping resistor and a dual secondary potential transformer will be installed in 2019 to avoid trips due to ferro-resonance conditions.

41.2 Please clarify whether the costs form part of FBC's formula O&M expenditures, regular capital expenditures, or CPCN capital expenditures for the Upper Bonnington Old Units Refurbishment (UBO)/Corra Linn Dam Spillway Gate Replacement projects.

Response:

The costs to address the failures were part of FBC's formula O&M expenditures and regular capital expenditures.

J. UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT STATUS REPORT

42.0 Reference: UPPER BONNINGTON OLD UNITS REFURBISHMENT PROJECT
Exhibit B-2, Application, Appendix C, pp. 4, 9, 14, 20
Project contingency

On page 20 of Appendix C of the Application, FBC provides Table C-2 which shows the Upper Bonnington Refurbishment project expenditures to June 30, 2018 and the forecast project expenditures to completion.

42.1 Please confirm, or explain otherwise, that there is a mathematical error in the "Spent to Date" column as it relates to the calculation of the total project cost.

Response:

Confirmed. An updated table is provided in response to BCUC IR 1.42.1.1. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

42.1.1 If confirmed, please provide a revised Table C-2 with corrected total project cost amounts for all columns.

Response:

A revised Table C-2 has been provided below. FBC has also provided the corrected table in the Errata filed concurrently with these IR responses.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Unit 3	4,079	6,128	86	6,214	52%	150%
Unit 4	6,634	5,027	2,393	7,419	12%	76%
Unit 1	8,050	668	6,805	7,473	-7%	8%
Unit 2	5,641	438	5,035	5,473	-3%	8%
Common	860	397	342	739	-14%	46%
Subtotal - Construction	**25,264**	**12,657**	**14,660**	**27,318**	**8%**	**50%**
Cost of Removal	1,880	826	670	1,496	-20%	44%
Project Contingency	3,771	(see Note 1)	1,781	1,781	-53%	0%
Subtotal-Construction	**30,916**	**13,483**	**17,112**	**30,585**	**-1%**	**44%**

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
& Removal						
AFUDC	867	314	874	1,188	37%	36%
Total Project Cost	**31,783**	**13,797**	**17,986**	**31,783**	**0%**	**43%**

Note: (1) Approximately $1.99 million of contingency has been allocated to Units 3, 4 and 1. This is reflected in the "Spent to Date" column for Units 3 and 4, and in the "Estimate to Complete" column for Unit 1 as described in the response to BCUC IR 1.43.2.

In the "Variance Explanations" column in Table C-2, FBC states "(the project c contingency has been reduced by $2.0 million to reflect significant proportion of engineering/procurement/construction complete)."

42.2 Please explain how FBC determined that reducing the project contingency by $2.0 million is appropriate at this time, with reference to the remaining scope of work, cost and mitigated risks of the Upper Bonnington Refurbishment project. Please include a breakdown of the $2.0 million reduced project contingency by contributing factors, if possible.

Response:

Contingency of approximately $2.0 million was re-allocated to other project line items to largely account for the following risks that materialized:

- Higher than anticipated generator rewind costs ($1.3 million); and
- Unforeseen turbine runner seal repairs for Unit 4 ($0.25 million).

The remainder (approximately $0.45 million) was used to address other risks that materialized, such as:

- the new high pressure governor system – the installation and commissioning of the new high pressure governor system required additional effort driven by the interfacing of modern equipment with an antiquated design;
- the new braking system – additional effort was required to confirm the feasibility of the new braking system installation;
- the new trash racks – the as-found condition of the trash rack support beams was worse than anticipated and replacement was required; and

- the generator rewind – the generator rewind scope of work was increased to account for the replacement of the pole to pole connectors and for the refurbishment of the rotor fans, which was required due to worse than anticipated as-found condition of these components.

Other cost pressures resulting from risks that materialized were offset by savings elsewhere.

Referencing Table C-2 Cost Summary, the Estimate to Complete for New Construction and Cost of Removal is approximately $15.330 million. The remaining contingency ($1.781 million) therefore represents a contingency of approximately 11.6 percent on future spend. The contingency is approximately 14.4 percent as a percentage of future spend if existing commitments (approximately $3.0 million) are removed.

FBC believes the contingency remaining is appropriate given the significant amount of engineering, procurement and construction that has been completed. The remaining project risks are largely related to the unknown condition of the mechanical components for Units 1 and 2.

On page 4 of Appendix C of the Application, FBC states “One exception is the generator stator and rotor rewind contract which is approximately $1.3 million over the estimate cost. This is partially offset by reduction in contingency and removal costs.”

On page 9, FBC states “[it] encountered some challenges throughout construction related to as-found conditions being worse than anticipated… The impact of these challenges were offset by savings elsewhere or were absorbed using contingency.”

Finally, on page 14, FBC states “The repair for the seals for Unit 4 is approximately $250,000 over the estimated cost. This additional cost is offset by reductions in contingency.”

42.3 Please clarify and explain why the amount in the project contingency “Spent to Date” column in Table C-2 is zero. For clarity, please explain how each of the additional costs noted in the preamble above are reflected in Table C-2.

Please discuss what actions FBC has undertaken to mitigate future budget variances.

Response:

The "Spent to Date" column for contingency in Table C-2 is zero as contingency used to offset the financial impact of materialized risks is reflected in the "Spent to Date" column and the "Estimate to Complete" for Units 3, 4, 1 and 2.

Once a risk materializes, "Contingency" is used to offset the financial impact. The financial impact will be reflected in either the "Spent to Date" column or the "Estimate to Complete" column, depending on whether the item is completed, for the respective unit impacted by the materialized risk. For example, as discussed in the Application[10], the agreement for the stator and rotor rewind was approximately $1.3 million over budget, which is approximately $0.44 million per unit. Contingency of $1.3 million was, therefore, allocated to the line items driving the variance. The $0.44 million variance for the Unit 3 rewind and the $0.44 million variance for the Unit 4 rewind is reflected in the Unit 3 and Unit 4 "Spent to Date" columns, respectively, since these items have been completed. The $0.44 million variance for the Unit 1 rewind is reflected in the Unit 1 "Estimate to Complete" column, since the Unit 1 rewind is scheduled for 2019 and has not yet occurred.

If FBC were to include this $0.44 million variance for Unit 1 rewind under the "Contingency – Spent to Date", it would increase the "Total Project Cost – Spent to Date" value. This would be misleading since the funds have not yet been spent. In this case, it is more accurate to show the variance under the "Estimate to Complete" column. It would also be misleading if FBC were to include the $0.44 million variance for Unit 1 rewind under "Contingency – Estimate to Complete". The remaining project contingency is meant to address risks that have not yet materialized. In this particular case, the $0.44 million variance for Unit 1 rewind is already certain. Including the $0.44 million variance for Unit 1 in "Contingency – Estimate to Complete" would therefore overstate the remaining contingency and would not distinguish between contingency remaining for risks that have yet to materialize and contingency committed for risks that have materialized.

In short, where contingency has been used to offset the financial impact of materialized risks, the financial impact is embedded in the "Spent to Date" column or the "Estimate to Complete" column for the respective units impacted. This avoids overstating "Total Project Cost – Spent to Date" and avoids overstating the remaining project contingency. As stated in the Application[11], FBC continues to make efforts to reduce the risk profile of the project through the use of lump sum contracts and the use of condition assessments, where possible. To date, FBC has completed a significant amount of procurement for the project which mitigates future budget variances.

Additionally, lessons learned throughout unit dismantle, construction, reassembly and commissioning are applied to future units which will result in efficiencies moving forward. For

[10] Appendix C, Section 3, Page 21, Lines 2-3.
[11] Appendix C, Section 4, Pages 22 to 23.

example, as discussed in the Application[12], FBC had difficulty interfacing the new high pressure governor system with the units antiquated design. While this resulted in a greater level of effort than anticipated, these learnings have since been applied to Units 4, 1 and 2.

With respect to the mechanical components for Units 1 and 2, due to the unit design, it is not possible to assess the condition of mechanical components prior to dismantling and therefore it is not possible to say prior to dismantling which components can be refurbished and which components require replacement. Nonetheless, FBC continues to evaluate its vendors for the machining and fabrication work to ensure the vendors are cost competitive and continues to work collaboratively with these machine shops to reduce the potential for cost and schedule impacts.

[12] Appendix C, Section 3, Page 21, Lines 9 to 11.

K. RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT

43.0 Reference: RUCKLES SUBSTATION REBUILD PROJECT STATUS REPORT
Exhibit B-2, Application, Appendix D, Section 1.4.3, p. 4
Emergency flood response

On page 4 of Appendix D of the Application, FBC states that additional emergency flood response from flooding in May 2018 resulted in approximately $70 thousand of additional costs to the project, but no significant schedule delays.

43.1 Please explain why it is appropriate to consider the additional emergency flood response in May 2018 as a cost of the Ruckles Substation Rebuild project. Would it be appropriate to record the $70 thousand of costs as O&M? Please explain why or why not.

Response:

The original forecast amount for the flood response was $70 thousand. The actual mitigation cost that was incurred was $30 thousand. Replacement of lost construction material, fence repairs, and other small costs were incurred due to the flood. Given the nature of the costs, their materiality, and that they were incurred directly in support of the construction of a capital asset, it is appropriate that they be included in the capital cost of the project.

44.0 Reference: RUCKLES SUBSTATION REBUILD PROJECT

Exhibit B-2, Application, Appendix D, Section 2.3, 3 and 4, pp. 10, 12

Project contingency

On page 12 of Appendix D of the Application, FBC provides an update of the Ruckles Substation Rebuild project contingency budget:

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percent Budget Spent	Variance Explanation
Project Contingency	805	0	314	314	-61%	0%	Identified potential risks did not materialize

FBC further states on page 12 of Appendix D that the remaining project risks relate to schedule, cost and environment.

44.1 Please explain what the "identified potential risks [that did] not materialize" are and the associated cost which reduced the project contingency budget from $805,000 to $314,000.

Response:

Contingency was originally calculated each month based on the forecast expenditures. Contingency was then released once it was determined that additional scope or unforeseen material or labour would not be required. This resulted in the release of $0.311 million. The major risks that did not transpire resulted in an additional release of $0.180 thousand of contingency.

The identified major risks that did not transpire were:

Risk Description	Likelihood rating	Cost impact
Ruckles T1 transformer leak repairs prior to relocation	high	$48 thousand
Ruckles T1/T2 transformers PCB contamination	high	$90 thousand
4 kV to 13 kV conversion delays	medium	$42 thousand

44.2 Please explain and provide a detailed breakdown of the remaining $314,000 project contingency into the identified schedule, cost and environmental risks.

Response:

The $314 thousand of project contingency contained $244 thousand in contingency allowance for scope changes and deficiencies, and $70,000 for major risks listed in the table below.

Risk Description	Likelihood rating	Cost impact
Additional excavation/soil disposal from oil leaks	medium	$44 thousand
Contaminated soil and material disposal from flood	high	$24 thousand
Grounding deficiencies	medium	$2 thousand

The Ruckles Substation Rebuild is now substantially complete and potential major risks did not materialize; consequently, the project contingency has been reduced to $10 thousand for the remaining project closeout/engineering activities. As a result, the forecast total to complete the project is reduced from $6.913 million to $6.438 million.

On page 10 of Appendix D, FBC states that project completion for the Ruckles Substation Rebuild project is still scheduled for August 2018.

44.3 Please provide an update on the current project timeline for the completion of the Ruckles Substation Rebuild project.

Response:

The Ruckles Substation Rebuild project is scheduled to be substantially completed by the end of September 2018. Project close out and engineering documentation will be finalized by November 2018.

Based on updated construction costs and the release of contingency as explained in the response to BCUC IR 1.44.2, the revised project forecast is reduced by $0.475 million compared to Appendix D, Table D-2, to $6.438 million, as shown in the table below.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Line Work	241	259	0	259	7	107
Civil & Site	1,688	1,526	146	1,672	(1)	90
Buildings	191	203	10	213	11	106
Structures & Buswork	427	481	23	505	18	113
Station Equipment & Apparatus	2,602	1,769	8	1,776	(32)	68
Communications & SCADA	32	33	0	33	6	106
Protection, Control & Metering	270	246	0	246	(9)	91
Design	627	673	22	695	11	107
Commissioning	132	122	0	122	(7)	93
Project Management	544	279	42	320	(41)	51
Subtotal - Construction	6,754	5,591	251	5,842	(13)	83
Cost of Removal	301	168	15	184	(39)	56
Project Contingency	805	0	10	10	(99)	0
Subtotal- Construction & Removal	7,860	5,760	276	6,036	(23)	73
AFUDC	428	287	116	403	(6)	67
Total Project Cost	8,288	6,046	392	6,438	(22)	73

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