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April 6, 2022

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: British Columbia Utilities Commission (BCUC) – 2022 Generic Cost of Capital Proceeding – Project No. 1599176

FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC) Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1 on FortisBC Evidence

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On January 18, 2021, BCUC initiated the proceeding referenced above. In accordance with the regulatory timetable established in BCUC Order G-288-21 for the review of FortisBC's Evidence, FortisBC filed its Evidence on January 31, 2022. FortisBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit A-11, BCUC IR 1 series, page 1&2; Exhibit B1-8, page 1-2.

On page 1 and 2 of Exhibit B1-8, FBCU states:

> The Fair Return Standard is a fundamental element of the regulatory compact and is captured in section 59(5) of the UCA [*Utilities Commission Act*]. The BCUC has confirmed that the Fair Return Standard requires that a fair and reasonable overall return (including a return on and of capital) is one that meets all three of the following requirements:
>
> - is comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enables the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - permits incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement). [Emphasis added]
>
> The 2013 GCOC Decision, citing the Supreme Court of Canada decision in *Northwestern Utilities Ltd. v. Edmonton (City), [1929] S.C.R. 186, (Northwestern Utilities)* at pages 192–193 describes the Fair Return Standard (FRS) as follows:
>
> > ... 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. [Emphasis added]

1.1 Please explain why the FRS, as defined by the Supreme Court of Canada, deals exclusively with external market comparatives of (attractiveness, stability, and certainty) and the FBCU interpretation suggests that the BCUC has defined it in terms of internal measures of the maintenance of financial integrity and ability to attract capital.

Response:

FEI and FBC do not agree with the distinction that appears to be made in the question.

First, the "FBCU interpretation" represents the articulation of the Fair Return Standard provided by the National Energy Board[1], which has been endorsed by the BCUC in subsequent decisions.[2]

Second, what CEC terms "external market comparatives" are referenced in the quoted articulation of the Fair Return Standard which references comparable investments, capital attraction and financial integrity (i.e., stability).

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[1] National Energy Board Decision RH-1-2008 in respect of Trans Quebec & Maritimes Pipeline.

[2] 2009 Cost of Capital Decision, p. 15; 2013 GCOC Stage 1 Decision, p. 50; 2016 Cost of Capital Stage 1 Decision, pp 3-5.

Third, the ability to attract capital, financial integrity and comparable investments are interrelated. The Supreme Court of Canada described the relationship between what the CEC terms "internal measures" and "external market comparatives" in considering the Fair Return Standard in *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 at para. 16:

> This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers…
>
> [Underlining added.]

1.2 Please confirm that at times capital markets can freeze up or become very strained or disrupted, and attraction of capital may be difficult or impossible at times for the FBCU and/or its comparable corporate investment entities.

Response:

That is correct and especially true for BBB rated entities as compared to A rated entities.

Please also refer to the response to BCUC IR1 6.4.

1.3 Please confirm that the financial integrity of the regulated enterprise, at least in significant part, is the responsibility of the management of FBCU and is dependent on corporate actions, inactions, and choices for deployment of capital.

Response:

FortisBC confirms that management plays an important role in maintaining financial integrity. However, parameters in which management operates are determined by external factors

including legislation, regulation and market conditions. The business risk appendices address a number of external factors that constrain management action.

1.4 Please provide FBCU's perspective as to why the FRS, as defined by the Supreme Court of Canada, chose not discuss at all the *return of capital*.

Response:

Please refer to the responses to BCUC IR1 1.1 and 1.1.2.

1.5 Please discuss why the return of capital should not be primarily based on the regulatory imperative to enable the regulated entity to recover costs prudently incurred for its planned used and useful contribution to benefiting the customers of the regulated utility, as opposed to being a function of the FRS.

Response:

Please refer to the responses to BCUC IR1 1.1 and BCUC IR1 1.1.2.

2. Reference: Exhibit A-11, BCUC IR 1 series, Page 2; Exhibit B1-8, page 10 and 2

On page 10 of the Exhibit B1-8, FBCU states, "The application of the Fair Return Standard ensures that utilities are in a position to:

[…]

- support the energy and environmental policy objectives of the BC government to the extent appropriate under the UCA; […]

1.2 Please clarify which of the three requirements under the FRS requires the support of energy and environmental policy objectives as FBCU notes above.

On page 2 of Exhibit B1-8, FBCU states:

> The application of the Fair Return Standard to FEI and FBC must account for the ongoing challenges that each utility respectively faces in attracting capital on reasonable terms and conditions. The overall return must reflect the business risks facing FEI and FBC that define the potential risks and uncertainties that each company faces in achieving a Fair Return on and of invested capital in both the short and long-term.

1.3 Please discuss how the risk of energy transition impacts each of the FRS requirements (comparable investment, financial integrity, and capital attraction) to FEI and FBC.

2.1 Please confirm that regulatory entity compliance with government legislation, including environmental legislation, is primarily a function of the management of the regulated entity and that the costs of doing so are regularly seen by regulators to be in the public interest and that the public interest in this sense is seen by regulators as a contribution to the benefit of the regulated entity's customers if prudently incurred.

Response:

FortisBC agrees that utility compliance with legislation, including environmental legislation, is primarily a function of the management of the utility, that the costs of doing so are regularly scrutinized by the regulator and that reasonably incurred costs are generally recovered in rates. However, as explained in FEI's business risk evidence, the BCUC and other regulators have oversight over many matters that are fundamental to the success of the utility business. Regulatory oversight involves the exercise of discretion, giving rise to regulatory risk. Decisions of a regulator can, for instance, adversely affect short-term earnings. They can also hinder the utility's ability to implement initiatives that align its operations with government policy and regulation, particularly with regards to climate policy related legislation and regulations.

Even if the regulator approves the costs and associated rates, the risk remains that the utility may not be able to recover all of its invested capital and this risk should be considered in determining a Fair Return.

Please also refer to the response to CEC IR1 17.1.

2.2 Please confirm that investment of capital in the securities of other comparable corporate investment opportunities would presume that these entities also have obligations to comply with government legislation and operate with regard to environmental and other social concerns in the public interest for the benefits of its customers.

Response:

Confirmed. However, the impact of legislation varies in different jurisdictions. For instance, as discussed in Concentric's evidence (Appendix C, Figure 40) many jurisdictions in the U.S. have passed legislation to prohibit local governments from (a) banning the use of gas in buildings and (b) implementing electrification codes. In BC, by contrast, the provincial and local governments are pursuing policies to restrict or even effectively ban the use of natural gas in the building sector. These differences in policy should be considered when using proxy groups to determine the appropriate ROE and capital structure.

2.3 Please confirm that while the FBCU is facing significant energy transition issues, there are many comparable entities with comparable transition issues in their business sectors that may have issues of raising capital through sale of their securities, and that certainly some of these entities are facing similar energy transition issues.

Response:

FortisBC agrees that other utilities are affected by the Energy Transition, although some utilities have been more affected than others.

As presented in Figure 49 of Concentric's evidence, approximately 50 percent of utilities in its U.S. gas proxy group face natural gas bans and electrification initiatives and 50 percent are in jurisdictions that prohibit gas bans and building electrification codes. FortisBC believes that compared with other jurisdictions in Concentric's proxy groups, BC is at the forefront of the Energy Transition, with all levels of government introducing new policies in rapid succession. This is apparent in the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap)[3] winning an award at the United Nations COP26 climate conference at Glasgow, Scotland.[4]

[3] https://cleanbc.gov.bc.ca/.

[4] https://news.gov.bc.ca/releases/2021ENV0068-002116.

2.4 Please discuss how energy transition issues impact each of the FRS criteria of attractiveness, stability, and certainty.

Response:

Please refer to the response to BCUC IR1 1.3.

2.5 Please discuss the role of the management of an entity in proactively implementing mitigations to the potentially challenging impacts of a transition, including an energy transition, such that the mitigations provide a path to attractiveness, stability, and certainty for the entity.

Response:

Management has a critical role to steer the company in the multi-decade Energy Transition. This includes putting forward initiatives that proactively address anticipated risks of the Energy Transition. FortisBC's management has been proactively pursuing business opportunities to mitigate the Energy Transition risk. For instance, FEI is the first gas utility in North America with a functional renewable natural gas program. Other examples of FEI's climate leadership are its Low Carbon Transportation and LNG export initiatives as well as its efforts to significantly increase its Renewable Gas supply which can partially mitigate some of the related escalating risks and materially reduce its customers' emissions.

Nevertheless, the successful implementation of these initiatives is uncertain and may depend on factors such as policy and regulatory support which are at least partially outside the control of management. As such, and as explained in Concentric's evidence, while alternative pathways such as RNG and hydrogen may offer a potential solution for FEI through the Energy Transition, investors perceive significant risk to those pathways and expect that the risks associated with these initiatives be reflected in the determination of the Fair Return.

2.6 Please confirm that there are many comparable entities facing transitions, including energy transitions, and which are engaged in implementing proactive mitigations of the challenges they face in dealing with the impacts of their transitions.

Response:

FortisBC cannot comment on whether other comparable utilities facing energy transition risk are proactively engaging in mitigation of these risks as it is not privy to management decisions in those companies. Nevertheless, FortisBC generally observes that some gas utilities are starting to consider or have already implemented projects to add Renewable Gas into their supply portfolio. Similarly, FortisBC observes that similar to FBC and in anticipation of increased use of EVs, some electric utilities are pursuing initiatives to increase customers' access to fast charging infrastructure.

2.7 Please provide the percentage of the provincial objectives for reductions in GHG emissions being provided by the FEI initiatives to provide renewable natural gas to date, and by those planned for the future, assuming regulatory support for these FEI energy transition risk mitigation activities.

Response:

FEI interprets this question to ask what share of the GHG reductions targeted by the provincial climate plan have and will come from FEI emission reduction initiatives.

The CleanBC Roadmap to 2030 (CleanBC Roadmap) released in late 2021 targets 26.7 Mt of GHG reductions by 2030. In 2020, FEI helped its customers avoid 420,000 tonnes of carbon dioxide emissions equivalent, which is approximately 1.5 percent of the total targeted GHG emissions reductions within the Roadmap. By 2030, FEI has been planning to help customers reduce at least 3.9 Mt of carbon dioxide emissions equivalent, which is approximately 15 percent of the total.

FEI's contribution to emission reductions in BC is expected to grow in order to comply with the proposed 6.11 Mt emissions cap for natural gas utilities that was introduced when the CleanBC Roadmap was released. Approximately 5.5 Mt, which is equivalent to a 47 percent reduction in the buildings and industry sectors combined and 21 percent of the total emissions reductions identified in the CleanBC Roadmap, will be accomplished by the emissions cap on natural gas utilities. FEI's share of the 5.5 Mt is uncertain at this time as further details on the emissions cap are not yet known and are key to knowing the role of different compliance mechanisms like renewable natural gas. FortisBC has conducted preliminary analysis on compliance pathways to achieve the cap. FEI expects that renewable and low-carbon gas could provide over half of the 5.5 Mt reductions with energy efficiency, carbon capture and storage and fuel switching in industry providing the balance. However, this expectation is based on policy being designed in a way that will allow FortisBC to undertake these actions.

2.8 Please confirm that FEI has plans to pursue as many cost-effective energy transition mitigation initiatives as it can reasonably implement to meet provincial GHG reduction targets.

Response:

The question as phrased includes some ambiguities / generalities that make FEI reluctant to simply confirm its accuracy. However, FEI understands the general sentiment and can confirm that it is a corporate priority to help achieve provincial GHG reduction targets, and believes that this can be done cost effectively.

3. Reference: Exhibit A-11, BCUC IR 4.4 series, Page 5

> 4.4 Please confirm, or explain otherwise, that FEI's projects, such as the TLSE Project are in line with provincial decarbonization targets.
>
> 4.4.1 If FEI can meet Provincial decarbonization targets, please discuss how this will impact FEI's competitive and operational landscape and the implications for FEI's customer rates and throughput. Please include a short-term vs. long-term assessment.
>
> 4.4.1.1 Please discuss the same if FEI cannot meet Provincial decarbonization targets. Please include a short-term vs. long-term assessment.

3.1 Please confirm that FEI is about to file its Long-Term Gas Resource Plan (LTGRP) and that FBC has already filed its Long-Term Electricity Resource Plan (LTERP).

Response:

Confirmed.

3.1.1 Please confirm that the evidence in these filings may be referenced, in this proceeding, from the FBCU point of view, without the need to file this evidence in this proceeding.

Response:

FortisBC is not opposed to parties referencing information from other proceedings in the context of asking information requests, which is how FortisBC interprets the proposal in the question. For clarity, FortisBC believes that it would be unnecessary and inefficient to have the entire resource plan filings simply deemed to be part of the evidentiary record in this proceeding; the resource plan filings are voluminous, and there are separate proceedings for assessing the plans.

3.2 Please confirm that FBCU's energy transition mitigation initiatives in these long-term planning filings are a significant focus of the FBCU long-term planning and that the FBCU intend to continue the development of energy transition mitigation initiatives and continue to improve their cost effectiveness.

Response:

Confirmed.

3.3 Please confirm that FBCU energy transition mitigation initiatives can be substantially and significantly impacted by regulatory decisions and government legislation and regulation, which can encourage and support the energy transition mitigations or can provide barriers to the same, all of which can impact the assessment of energy transition risks.

Response:

Confirmed.

3.4 Please confirm that to the extent FBCU has encouragement, support, and removal of barriers assistance in the future from regulators and governments, this could substantially reduce the energy transition risks to the FBCU.

Response:

Yes, it could mitigate the developing Energy Transition risk. Political risk, which considers the impact of government policies and regulation on utility operations, is a major component of the Energy Transition risk. As such, to the extent that political risk is mitigated (through measures that are supportive of the role of gas system in decarbonization and removing barriers to its use for example), the Energy Transition risk is also positively impacted. Further, as explained in FortisBC's evidence, regulatory support will be essential to FortisBC's initiatives to mitigate these risks.

3.5 Please confirm that FEI's investment in bringing on RNG enables its customers to avoid carbon taxes at $50/CO2te in 2022 and $170/ CO2te.

Response:

Confirmed. However, currently, the price for natural gas, even after considering the carbon tax, is lower than the price for RNG.

For instance, assuming an average RNG price of $22 per GJ, FEI's existing gas commodity rate of $4.503 per GJ and the carbon tax of $2.5588 per GJ for April 2022, the natural gas is approximately $15 per GJ less costly than RNG even after considering the carbon tax.

By 2030, the carbon tax is expected to increase to $8.40 per GJ. Keeping the gas commodity rate constant at $4.5 per GJ, the RNG price premium would shrink to approximately $9 per GJ. FEI expects that potential technological advancements in the Renewable Gas sector can further reduce the average price gap between acquired renewable and natural gas; however, the potential magnitude of cost reduction is uncertain at this time.

4. Reference: Exhibit B1-8-1, Appendix D, page 5

FortisBC Energy Inc.
Consolidated Statements of Earnings
For the years ended December 31
(in millions of Canadian dollars)

	2020	2019
Revenue (note 17)	**$ 1,385**	$ 1,330
Expenses		
Cost of natural gas	**469**	437
Operation and maintenance (notes 4 and 24)	**272**	265
Property and other taxes	**68**	68
Depreciation and amortization (notes 6, 7 and 8)	**241**	240
Total expenses	**1,050**	1,010
Operating income	**335**	320
Other income (notes 18 and 24)	**70**	94
Finance charges (notes 19 and 24)	**205**	213
Earnings before income taxes	**200**	201
Income tax expense (note 21)	**11**	18
Net earnings	**189**	183
Net earnings attributable to non-controlling interests	**1**	1
Net earnings attributable to controlling interest	**$ 188**	$ 182

4.1 Please confirm that the 40% and 30% limitation is a percent of EBITDA.

Response:

As discussed in FortisBC's evidence, the proposed earnings-stripping rule limits the amount of net interest expense that a corporation may deduct in computing its taxable income to no more than a fixed ratio of "Tax EBITDA". Tax EBITDA is generally defined as a corporation's taxable income before taking into account interest expense, interest income and income tax, and deductions for depreciation and amortization, where each of these items is determined for tax purposes. This amount would not be the same as Accounting EBITDA.

Please also refer to the response to BCUC IR1 5.3.

4.2 Please confirm that from the above 2020 financial statement EBITDA for FEI would consist of $335 million in EBIT and $576 million in EBITDA, and that 40% limit for this would be $230 million (above the current financing charges) and the 30% for this would be $173 million (potentially invalidating $32 million of tax deduction).

Response:

As discussed in the response to CEC IR1 4.1, the proposed earnings-stripping rule limits the amount of net interest expense that a corporation may deduct in computing its taxable income to no more than a fixed ratio of "Tax EBITDA". Therefore, the EBITDA amounts calculated using

the 2020 financial statements amounts are not relevant for determining the relevant interest deductibility thresholds and the amount of restricted interest expense.

For more information regarding the potential impact of these proposed rules (as currently drafted) please refer to the response to BCUC IR1 5.3.

4.2.1 Please confirm that the consequence of this would be increased Canadian Government taxation and that FEI would be able to recover these taxes under current regulatory RRA processes from its customers.

Response:

The higher tax cost associated with the restricted generated expense would result in an uncontrolled tax variance that would be borne by ratepayers. This would lead to higher rates for ratepayers and a less efficient capital structure.

4.2.2 Please confirm this would not compromise FEI's recovery of costs but would increase its costs and diminish FEI's cost structure competitiveness.

Response:

Confirmed. Please refer to the responses to CEC IR1 4.2.1 and BCUC IR1 5.3.

5. Reference: Exhibit B1-8, page 38

Table 6-5: Capital Cost for FEI's Major Capital Projects for 2019-2026

FEI's Major Capital Projects[1] (C$ millions)	Actuals[2] 2019	2020	Pro-Forma[3] 2021	2022	2023	2024	2025	2026	Total Project Costs[4]	Approval
Tilbury 1B	7.8	12.1	-	32.1	40.6	52.2	80.9	-	400.0	OIC
Inland Gas Upgrades Project	8.2	50.1	99.3	93.5	67.4	31.2	-	-	360.2	BCUC
Okanagan Capacity Upgrade	-	7.9	11.3	113.5	139.2	-	-	-	271.3	Under Review
Pattullo Bridge Crossing Replacement	-	6.4	51.9	118.7	11.3	2.9	-	-	191.7	BCUC
TIMC CTS[5]	-	9.4	21.3	7.4	4.5	92.5	2.9	-	137.8	Under Review
Advanced Metering Infrastructure	-	-	28.0	17.1	116.1	193.3	182.9	97.5	638.4	Under Review
Tilbury LNG Storage Expansion	-	8.6	4.6	16.0	165.8	251.7	210.2	110.9	769.0	Under Review
Sustainment and other capital[6]	151.5	163.2	166.1	159.7	162.2	165.8	169.2	172.5	995.5	
Total	167.5	257.7	382.5	560.0	707.1	789.6	646.1	380.9	3,763.9	

[1] Woodfibre LNG has been excluded from FEI's Major Capital projects shown in this table.
[2] Actuals are from 2019-2020 Annual Reports filed with BCUC.
[3] 2021-2026 figures are from CPCNs and OICs filed with an exception of Sustainment and other capital (see note below).
[4] Total Project Costs include capital expenditures prior to 2019 and subsequent to 2026 and were compiled based on CPCNs and OICs filed with an exception of Sustainment and other capital (see note below).
[5] TIMC CTS stands for Transmission Integrity Management Capabilities Project, Coastal Transmission System.
[6] Sustainment and other capital figures are per 2019-2021 Annual Reports filed with BCUC and 2020-2024 MRP Application. For 2025 and 2026, FortisBC assumed 2% escalation over prior year. Total Sustainment and other capital is for 2021-2026.

5.1 Please describe the way in which any of these capital projects are investments in energy transition mitigation.

Response:

Please refer to the responses to BCUC IR1 9.4 and 18.4.

5.2 Please confirm that these capital investments are being made to improve natural gas system integrity, resilience, reliability and capacities.

Response:

Please refer to the responses to BCUC IR1 9.4, 11.4 and 18.4.

5.3 Please confirm that when FEI is addressing these issues it is substantially reducing risks that other natural gas utilities may face and is getting out ahead of potential failure risks, which if realized could significantly impact its financial attractiveness, stability, and certainty, given that asset safety and reliable performance impact all three of these criteria.

Response:

Please refer to the responses to BCUC IR1 19.1 and 19.2.

5.4 Please describe any projects and their progress status and future timetables that FEI or FBCU is making or planning to make investments in for RNG, Hydrogen, Synthetic Natural Gas, Carbon Capture and Storage, Carbon Capture & Use, and any other technologies for mitigating energy transition issues.

Response:

FEI has thirty RNG (biomethane) project applications that have been accepted by the BCUC and that are in different stages of development, and a number of other potential supply opportunities in various stages of negotiation in which FEI is planning to invest. To date, FEI has either invested in or will invest in thirteen of these projects – all in BC. The amount of investment will vary based on whether or not FEI is investing in RNG production equipment (upgrading) or simply receiving gas on its system.

FEI is also enabled under the Greenhouse Gas Reduction Regulation (GGRR) to make investments in hydrogen projects. FEI has identified a number of potential investment opportunities in hydrogen projects; however, early stage work to determine the project feasibility has not been completed so it is too early to report on project details, progress status and future timetables.

Amendments to the GGRR would be required to enable any investments in commercial Synthetic Natural Gas, Carbon Capture and Storage and Use projects. (The GGRR currently only enables utility investment in RNG projects and certain types of low-carbon hydrogen, synthesis gas (syngas) and lignin project assets).

Through the Clean Growth Innovation Fund, FEI is providing grants for pre-commercial and pilot projects that reduce emissions in British Columbia. As part of its Annual Review for 2022[5] FEI provided information on approved expenditures to date. Details of the individual projects and the grants approved can be found in Table 10-7 of that filing (reproduced below).

[5] (Exhibit B-2 https://docs.bcuc.com/Documents/Proceedings/2021/DOC_63692_B-2-FEI-Annual-Review-2022-Delivery-Rates-Appl.pdf)

Primary Partner	Category	CGIF Funding Approved	Project Description
NGIF	Carbon Capture	$92,015	Field pilot of carbon recycling system designed to lower oil & gas emissions directly at source. The unit captures CO2 directly from any flue stack of sufficiently large volume, and converts it into marketable mineral feedstocks.
NGIF	Carbon Capture	$28,042	Testing of an adsorption technology using waste heat from a CHP that uses less electricity vs conventional chillers.
NGIF	Carbon Capture	$51,414	Demonstration of membrane-based carbon capture technology for flue emissions.
NGIF	Carbon Capture	$150,000	Retrofit of Once-Through Steam Generator with modular decarbonization systems reduce 90 percent of the carbon emissions. If successful, this technology has potential for carbon capture in marine natural gas transportation applications.
	Carbon Capture Total	**$321,471**	
NGIF	Combined Heat & Power	$15,110	Demonstration of a commercial building using natural gas, CHP's and solar panels disconnected from the electrical grid.
	Combined Heat & Power Total	**$15,110**	
NGIF	Low-Carbon Syngas	$25,707	Development of patented photocatalysts to convert carbon dioxide (CO2) and methane (CH4) simultaneously into low carbon-intensity synthesis gas.
	Low-Carbon Syngas Total	**$25,707**	
UBCO	Low-Carbon Hydrogen	$500,000	Development of a novel scalable and automated hydrogen-enriched natural gas (HENG) laboratory setup for conducting an integrated experimental studies on the performance and feasibility of HENG - from injection, mixing quality, material exposure, separation and combustion, to emission.
NGIF	Low-Carbon Hydrogen	$77,122	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
NGIF	Low-Carbon Hydrogen	$42,845	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
NGIF	Low-Carbon Hydrogen	$25,707	Testing of a patented nano-catalyst that can reduce cost of PEM electrolysers used in production of hydrogen by reducing the amount of platinum catalyst required.
NGIF	Low-Carbon Hydrogen	$114,084	This project will test technology that could reduce the cost of large-scale electrolysers. The testing will be in environments which will validate some of its key features, advantages, and benefits. This project will specifically test the ability to directly couple with solar and wind applications with variable load.
NGIF	Low-Carbon Hydrogen	$70,000	The project objective of this initiative is to demonstrate a novel process which uses renewable energy to split a mineral salt and water, producing hydrogen, hydroxide, sulfuric acid and oxygen. The hydroxide is combined with CO2 and then added to seawater, permanently sequestering CO2 as bicarbonate. This project will construct and operate a negative emissions hydrogen pilot plant.

Primary Partner	Category	CGIF Funding Approved	Project Description
NGIF	Low-Carbon Hydrogen	$38,560	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
	Low-Carbon Hydrogen Total	**$868,318**	
NGIF	Renewable Natural Gas	$77,121	Piloting the integration of technologies to improve RNG production by allowing the co-digestion of dairy, poultry and hog manure.
NGF (UBC)	Renewable Natural Gas	$105,000	Testing of an integrated pyrolysis system coupling pre-treatment, anaerobic digester and post-treatment to improving carbon conversion efficiency and lower the biogas and renewable natural gas production cost.
NGIF	Renewable Natural Gas	$77,121	Demonstration of the conversion of wood waste into both RNG and biocoal on a commercial scale. Biocoal would allow large industrial companies to reduce their reliance on fossil coal, while the natural gas distribution industry would benefit from additional access to lower-cost RNG.
NGIF	Renewable Natural Gas	$77,121	Developing of technology to convert forestry waste and agricultural crop waste into renewable natural gas (RNG). The proposed project will validate the design for scaling up existing technology. The project will include detailed design, construction, and testing of a system capable of processing 1 tonne of biomass per day. Supporting subsystems for surrogate methanation gas supply, instrumentation, controls, and data collection are also be included in the project.
	Renewable Natural Gas Total	**$336,363**	
NGF (UBC)	Transportation	$65,000	Experimental and field work to reduce the GHG emissions from natural gas engines using a combination of lab-based engine experiments, as well as field measurements of GHG emissions from in-use engines. The lab-based studies will develop methodologies for in-use emission characterization and strategies for emissions reductions, based on operating conditions of field engines. This will provide technologies for low GHG emission transportation systems and provide quantitative emission characterization for inventory and policy development purposes.
	Transportation Total	**$65,000**	
NGIF	Uncategorized	$215,253	NGIF operations and administration expenses per the NGIF/FortisBC Master Funding Agreement.

Primary Partner	Category	CGIF Funding Approved	Project Description
NGF (UBC)	Uncategorized	$130,000	• R&D on fugitive methane emissions quantification system • LNG transfer technology • Testing prototype micro-carbon capture and utilization system • R&D on combustion emissions sensing system • R&D on engine combustion emissions mitigation technologies (e.g. cylinder deactivation, air-fuel ratio optimization) • R&D on renewable energy (e.g. RNG) production and integration systems
	Uncategorized Total	**$345,253**	
	Grand Total	**$1,977,223**	

5.5 Please describe the degree to which FEI or FBCU energy transition mitigation risks are dependent on FEI being able to arrange financing or whether or not financing for energy transition mitigation initiatives is more likely to be a function of energy supplier investments.

Response:

FEI assumes that the question is asking whether the investments to mitigate Energy Transition risks are dependent on FEI's ability to arrange financing or whether these investments are dependent on energy suppliers' ability to finance these investments.

FEI believes that investments to mitigate these risks depend on the ability to finance the mitigation strategies in the entire supply chain, from conventional natural gas suppliers' ability to finance their strategies to limit their carbon intensity and methane leakages to RNG suppliers' ability to grow and FEI's ability to arrange financing for its own initiatives to reduce its customers emissions.

6. Reference: Exhibit B1-8-1, page 9 and 83

Table A2-1: FEI's Business Profile[6]

	2015[7]	2022[8]
Type of Utility	Local Distribution Company (LDC)	
Energy Product Offering	Natural gas, biomethane, propane	
Service Area	Mainland, Vancouver Island, and Whistler	
Rate Base ($000s)	3,661,370	5,409,207
Sales/Transportation Volumes (TJ)	176,035	234,057
Average Number of Customers	970,389	1,068,458
Customer Profile by Demand		
Residential	42%	41%
Commercial	32%	29%
Industrial	26%	31%
Customer Profile by Sales Revenue		
Residential	60%	57%
Commercial	33%	27%
Industrial	7%	12%

Table A7-1: FEI's Net Customer Additions by Segment and in Total

Year	2015	2016	2017	2018	2019	2020	2021
Residential	12,508	11,359	13,357	19,257	10,609	12,995	10,241
Commercial	1,673	965	1,060	1,794	610	386	479
Industrial	51	6	22	16	50	19	10
Total	14,232	12,330	14,439	21,067	11,269	13,400	10,730

6.1 Please confirm that FEI has seen its sales and transportation volumes grow by 33% and its rate base has grown by 47.7% over the period between 2015 and 2022, or explain where this is provided in the evidence.

Response:

Confirmed. However, FortisBC notes as indicated by Footnotes 7 and 8 of Appendix A, the numbers shown for 2015 and 2022 in Table A2-1 are from FEI's 2015 and 2022 Annual Reviews, as such they are forecasts for 2015 and 2022, respectively. Based on the actual amounts for 2015 as shown in the response to BCUC IR1 11.1, the sales and transportation volumes increased by approximately 26 percent while FEI's rate base increased by approximately 48 percent.

The growth in FEI's rate base is higher than the growth in volumes, as a large portion of FEI's growth in rate base has been related to sustainment capital for the purpose of maintaining safe and reliable services through FEI's natural gas system, and therefore, not directly related to FEI's growth in volume or customers. Given the fact that FEI's growth in rate base is largely related to sustainment and reliability of existing assets and that rate base is growing faster than FEI's volumes, it is resulting in higher rates for FEI's customers and further reinforces the increased

risks in FEI's business profile as well as the demand/market risk of FEI as discussed in Sections 2 and 7, respectively, in Appendix A of FEI's evidence. Please also refer to the response to BCUC IR1 11.4 for further discussion of FEI's growth in rate base which includes sustainment capital, growth capital, and capital in response to BC Government Policy, as well as the relationship between growth in rate base and growth in volumes/customers.

6.2 Please provide the carbon tax in $/GJ for each year from 2015 to 2022.

Response:

As of April 1, 2022, BC's carbon tax is set at $2.5588/GJ; this level is 72 percent higher than the carbon tax rate in 2015. BC's historical carbon tax rates are provided in the table below. As can be seen, from July 1, 2012 to April 1, 2018 the carbon tax remained unchanged at 1.4898 $/GJ.

Table A6-1: BC Carbon Tax Rates for Natural Gas Since 2012

	July 1, 2012 till April 2018	April 1, 2018	April 1, 2019	April 1, 2021	April 1, 2022
Carbon Tax Rate ($/GJ)	1.4898	1.7381	1.9864	2.3053	2.5588

6.3 Please provide the customer attrition for each year from 2015 to 2021 in terms of number of customers and demand volume reduction, or explain where this is provided in the evidence.

Response:

Please refer to the response to BCUC IR1 11.1 for the annual volumes and customer count since 2013 as well as BCOAPO IR1 3.1 for the breakdown by customer type (i.e., residential, commercial, industrial and low carbon transportation). However, FEI clarifies that although FEI has not yet experienced customer attrition in the overall volume as well as customer count, growth has slowed in recent years, as shown in Table A7-1 referenced in the preamble above. It shows FEI's net customer additions, especially for residential and commercial customers, have been on a consistent decline since the peak in 2018. In other words, although FEI is still experiencing growth in customers (i.e., net customer additions) in recent years and therefore growth in volume, the rate of the growth has slowed.

6.4 Please provide the estimated net new building constructions for each year from 2015 to 2021, or explain where this is provided in the evidence.

Response:

The table below shows the BC Assessment Data for new construction residential buildings that were built in or have an effective year of 2015 thru to 2020 in BC. The data is provided to FEI by Landcor Data Corporation and due to the time lag of data being sourced by FEI, FEI does not currently have the 2021 stats.

Type	2015	2016	2017	2018	2019	2020
Residential	21,502	24,698	24,833	23,750	24,739	22,199

6.5 Please provide the average temperature change for each year from 2000 to 2021 for the jurisdiction area FEI serves and, if necessary for providing the Commission useful information, provide it on a weighted basis for customers by significant temperature variance area.

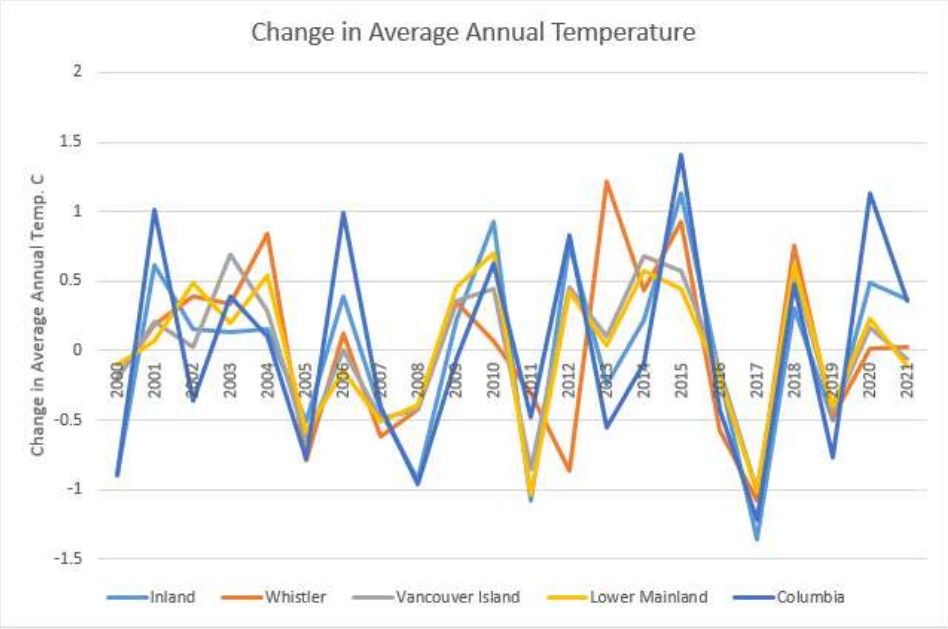
Response:

The following table shows the change in the average annual temperature (degrees C) from 2000 to 2021 for the regions shown.

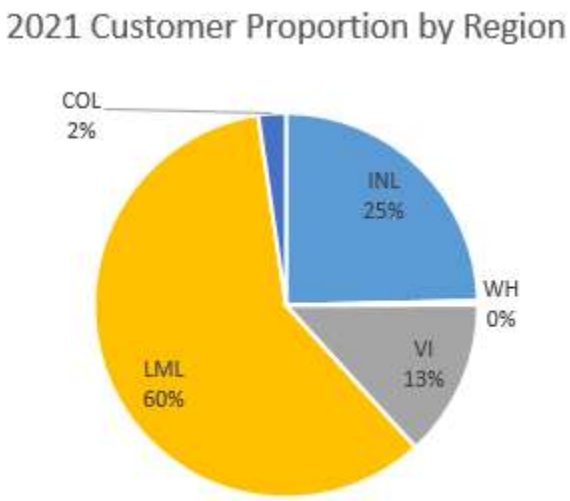
Table 1: Change in Annual Average Temperature

Year	Inland	Whistler	Vancouver Island	Lower Mainland	Columbia
2000	-0.9	-0.2	-0.2	-0.1	-0.9
2001	0.6	0.2	0.2	0.1	1.0
2002	0.2	0.4	0.0	0.5	(0.4)
2003	0.1	0.3	0.7	0.2	0.4
2004	0.2	0.8	0.3	0.5	0.1
2005	(0.5)	(0.8)	(0.7)	(0.6)	(0.8)
2006	0.4	0.1	(0.0)	(0.2)	1.0
2007	(0.4)	(0.6)	(0.5)	(0.5)	(0.4)
2008	(0.9)	(0.4)	(0.4)	(0.4)	(1.0)
2009	0.2	0.4	0.4	0.5	(0.1)
2010	0.9	0.1	0.4	0.7	0.6
2011	(1.1)	(0.3)	(0.9)	(1.0)	(0.5)
2012	0.8	(0.9)	0.5	0.4	0.8
2013	(0.2)	1.2	0.1	0.0	(0.6)
2014	0.2	0.4	0.7	0.6	(0.1)
2015	1.1	0.9	0.6	0.4	1.4
2016	(0.2)	(0.6)	(0.1)	(0.2)	(0.4)
2017	(1.4)	(1.1)	(1.0)	(1.0)	(1.2)
2018	0.3	0.8	0.6	0.6	0.5
2019	(0.5)	(0.5)	(0.4)	(0.4)	(0.8)
2020	0.5	0.0	0.2	0.2	1.1
2021	0.4	0.0	(0.1)	(0.1)	0.4

The following figure shows the data from Table 1 graphically:



To provide a customer-based weighting FEI used the 2021 actual proportions of residential and commercial customer counts, as shown in the following figure:

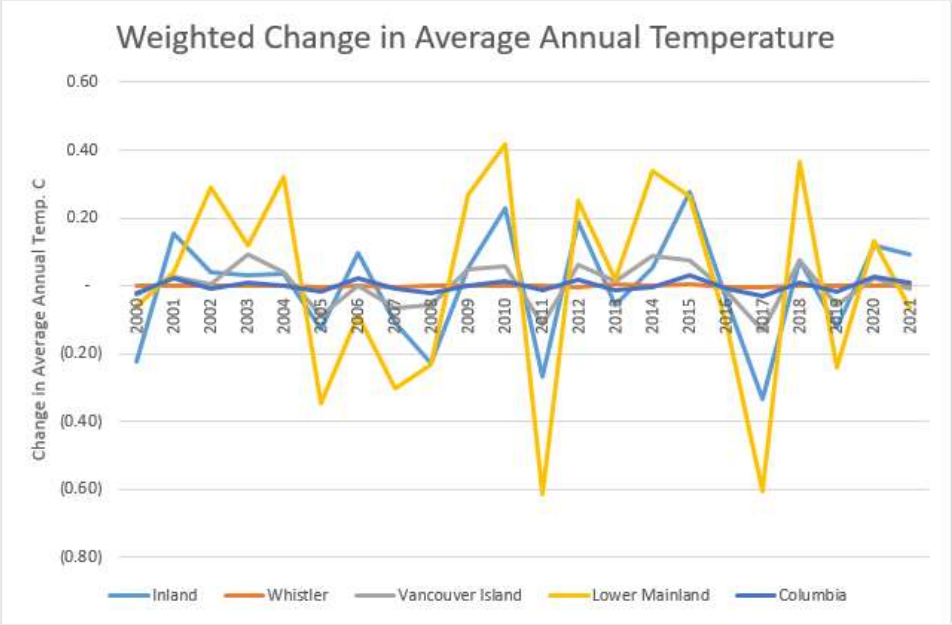


The percentages were used as multipliers to develop the following weighted version of Table 1.

Table 2: Customer-Weighted Change in Annual Average Temperature

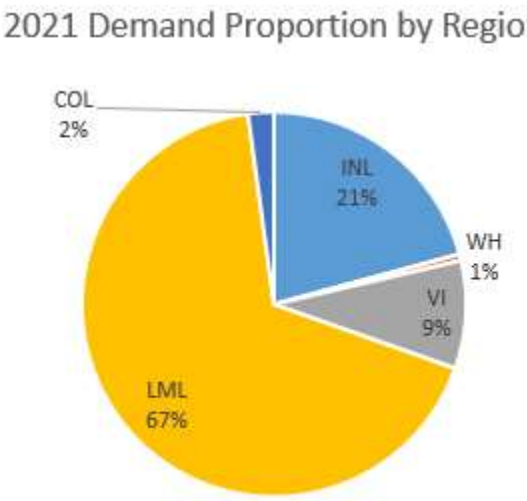
Year	Inland	Whistler	Vancouver Island	Lower Mainland	Columbia
2000	(0.22)	(0.00)	(0.03)	(0.06)	(0.02)
2001	0.15	0.00	0.03	0.04	0.02
2002	0.04	0.00	0.00	0.29	(0.01)
2003	0.03	0.00	0.09	0.12	0.01
2004	0.04	0.00	0.04	0.32	0.00
2005	(0.13)	(0.00)	(0.09)	(0.34)	(0.02)
2006	0.10	0.00	(0.00)	(0.09)	0.02
2007	(0.11)	(0.00)	(0.07)	(0.30)	(0.01)
2008	(0.23)	(0.00)	(0.06)	(0.23)	(0.02)
2009	0.05	0.00	0.05	0.27	(0.00)
2010	0.23	0.00	0.06	0.42	0.01
2011	(0.27)	(0.00)	(0.11)	(0.61)	(0.01)
2012	0.19	(0.00)	0.06	0.25	0.02
2013	(0.06)	0.00	0.01	0.02	(0.01)
2014	0.05	0.00	0.09	0.34	(0.00)
2015	0.28	0.00	0.08	0.26	0.03
2016	(0.04)	(0.00)	(0.02)	(0.12)	(0.01)
2017	(0.33)	(0.00)	(0.13)	(0.60)	(0.03)
2018	0.07	0.00	0.07	0.36	0.01
2019	(0.12)	(0.00)	(0.06)	(0.24)	(0.02)
2020	0.12	0.00	0.02	0.13	0.03
2021	0.09	0.00	(0.01)	(0.07)	0.01

1 The following figure shows the data from Table 2 graphically:



2

3 Although the CEC asked for customer-weighted information, FEI believes the more informative
4 view would be demand-weighted. To provide a demand-based weighting FEI used the 2021
5 actual proportions of residential and commercial customer demand, as shown in the following
6 figure:



7

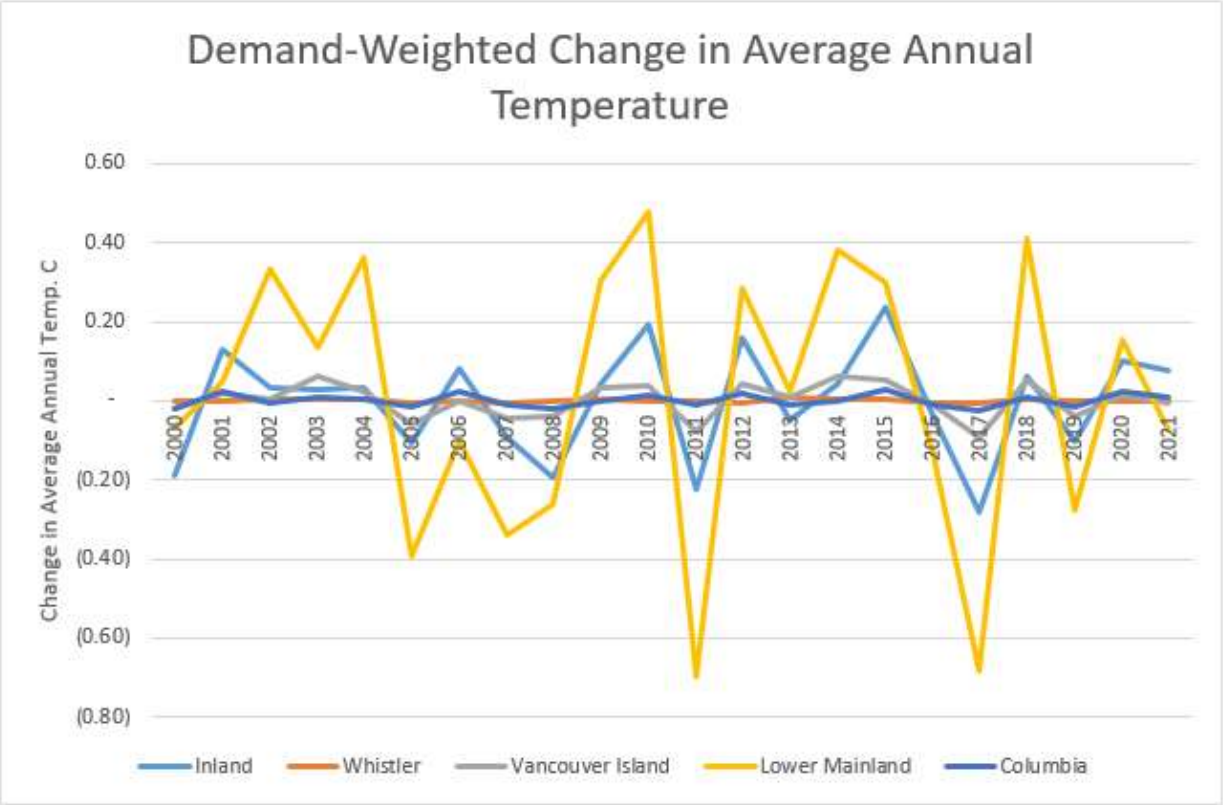
8 The percentages were used as multipliers to develop the following weighted version of Table 1.

1 **Table 3: Demand-Weighted Change in Annual Average Temperature**

Year	Inland	Whistler	Vancouver Island	Lower Mainland	Columbia
2000	(0.19)	(0.00)	(0.02)	(0.07)	(0.02)
2001	0.13	0.00	0.02	0.05	0.02
2002	0.03	0.00	0.00	0.33	(0.01)
2003	0.03	0.00	0.06	0.14	0.01
2004	0.03	0.00	0.03	0.36	0.00
2005	(0.11)	(0.00)	(0.06)	(0.39)	(0.02)
2006	0.08	0.00	(0.00)	(0.10)	0.02
2007	(0.09)	(0.00)	(0.04)	(0.34)	(0.01)
2008	(0.19)	(0.00)	(0.04)	(0.26)	(0.02)
2009	0.05	0.00	0.03	0.30	(0.00)
2010	0.19	0.00	0.04	0.48	0.01
2011	(0.23)	(0.00)	(0.08)	(0.70)	(0.01)
2012	0.16	(0.00)	0.04	0.28	0.02
2013	(0.05)	0.01	0.01	0.02	(0.01)
2014	0.04	0.00	0.06	0.38	(0.00)
2015	0.23	0.01	0.05	0.30	0.03
2016	(0.04)	(0.00)	(0.01)	(0.14)	(0.01)
2017	(0.28)	(0.01)	(0.09)	(0.68)	(0.03)
2018	0.06	0.00	0.05	0.41	0.01
2019	(0.10)	(0.00)	(0.04)	(0.27)	(0.02)
2020	0.10	0.00	0.02	0.15	0.02
2021	0.08	0.00	(0.01)	(0.08)	0.01

2

3 The following figure shows the data from Table 3 graphically:



6.6 Please provide FEI's investment in DSM for each year from 2015 to 2021 and the UPC for each class of customer for each year from 2015 to 2021.

Response:

Please refer to Table 1 below for FEI's investment in DSM from 2015 to 2021 and Table 2 below for the average UPC of each class of customer from 2015 to 2021. FEI's 2015 to 2018 DSM expenditures were approved by Order G-138-14[6] and the 2019 to 2021 DSM expenditures were approved by Order G-10-19[7]. FEI notes that expenditures under the program areas of Conservation Education and Outreach, Innovation Technologies, Enabling Activities and Portfolio Level Activities are not specific to any customer classes. FEI also notes that the 2021 numbers in both Tables 1 and 2 below are based on preliminary results.

FEI cautions that it is not expected that a correlation between the average UPC and the DSM expenditures would be seen over the same period nor a proportional reduction in UPC in

[6] FEI 2014-2019 PBR Plan Decision, p. 277.

[7] Pursuant to Order G-301-21, FEI was approved to increase the expenditure level by $24.982 million and pursuant to Order G-345-21, FEI was approved a carryover amount of $-1.388 million from 2020 to 2021.

comparison to the DSM expenditures. DSM measures are expected to result in reductions in demand over time (e.g., the average weighted measure life of DSM measures is approximately 16 years[8]). Further, the reduction in demand would only reflect those customers that participated in FEI's DSM programs while the average UPC includes both participating and non-participating customers in FEI's DSM programs.

Table 1: FEI's DSM Expenditures from 2015 to 2021

Program Areas	2015	2016	2017	2018	2019	2020	2021
Residential	$ 12,735	$ 12,531	$ 12,203	$ 12,584	$ 22,084	$ 32,880	$ 51,484
Commercial	$ 10,746	$ 10,637	$ 10,834	$ 10,098	$ 11,709	$ 13,571	$ 21,309
Industrial	$ 989	$ 1,003	$ 2,099	$ 3,195	$ 6,481	$ 6,124	$ 6,095
Low Income	$ 1,550	$ 2,277	$ 2,644	$ 2,713	$ 6,719	$ 7,176	$ 9,043
Conservation Education and Outreach	$ 2,830	$ 2,415	$ 2,590	$ 3,122	$ 6,059	$ 5,165	$ 4,517
Innovative Technologies	$ 626	$ 757	$ 928	$ 1,049	$ 2,027	$ 2,142	$ 3,721
Enabling Activities	$ 1,189	$ 1,378	$ 1,181	$ 1,260	$ 8,077	$ 7,761	$ 9,199
Portfolio Level Activities	$ 1,200	$ 1,167	$ 1,559	$ 1,450	$ 1,339	$ 1,003	$ 1,477
Total	**$ 31,865**	**$ 32,165**	**$ 34,038**	**$ 35,471**	**$ 64,495**	**$ 75,822**	**$ 106,845**

Table 2: FEI's Average UPC for Residential, Commercial, and Industrial from 2015 to 2021[9]

Average UPC (GJ)	2015	2016	2017	2018	2019	2020	2021
Residential	84.4	87.5	85.8	85.1	82.4	86.2	85.4
Commercial	611.6	623.6	623.9	621.5	601.4	599.3	611.6
Industrial	83.0	88.9	94.4	91.1	91.1	90.7	87.5

6.7 Please discuss the GHG reduction from FEI's promotion of conservation and efficiency over this time frame.

Response:

The table below shows the growing annual and lifetime GHG emission reductions from energy savings that have resulted from FEI's DSM activities over that time period as presented in FEI's DSM Annual Reports.

[8] FEI's 2019-2022 DSM Expenditures Plan, Appendix J.

[9] The average UPCs for residential and commercial rate classes are weather-normalized demand while the UPC for the industrial rate class is based on actual demand.

Annual GHG Emission Reductions as a Result of FEI's DSM Activity (tonnes CO2e/year)

	Year:	2015	2016	2017	2018	2019	2020	2021	Total
Residential	Annual GHG Emission Reductions*	7258	7287	8202	13366	11514	20121	17923	85671
	Measure Lifetime GHG Emission Reductions	69416	73590	86508	137660	124626	144102	224106	860006
Commercial	Annual GHG Emission Reductions	16202	15273	14274	14007	16816	20002	24733	121306
	Measure Lifetime GHG Emission Reductions	105037	116151	114027	105539	162379	131704	279757	1014594
Industrial	Annual GHG Emission Reductions	991	1097	6310	7377	18040	16107	17806	67728
	Measure Lifetime GHG Emission Reductions	7929	9416	60219	58201	145765	147409	192881	621820
Low Income	Annual GHG Emission Reductions	1441	2208	2826	2699	3184	4568	3029	19955
	Measure Lifetime GHG Emission Reductions	10282	16188	20516	21625	29313	42914	31352	172191
Total	Annual GHG Emission Reductions	25893	25866	31612	37448	49553	60799	63491	294661
	Measure Lifetime GHG Emission Reductions	192664	215345	281270	323026	462083	466128	728096	2668611

**(factor: x 0598) life cycle emission factor. Takes upstream emissions into account.*

7. Reference: Exhibit B1-8-1, page 16

> flow from customers. Compared to the 2016 Proceeding, and considering the unprecedented economic turmoil and uncertainty caused by the COVID-19 pandemic and record high inflation numbers due to government fiscal and monetary policy to boost economic growth and improve employment as well as BC's challenges for long-term economic growth, FEI assesses that the economic condition risk has increased.

7.1 Please confirm that in uncertain times the investments in stable regulated utilities with regulated assured returns of capital and return on capital are very attractive to investors.

Response:

As confirmed by Concentric in its response to BCUC IR1 39.3.2, regulated utilities are generally considered to have lower risk than the broad market. However, as explained in the response to BCUC IR1 10.1.1, it is incorrect to suggest that regulated utilities have a "assured return".

Further, as discussed in Concentric's evidence, since January 2020, and compared to historical levels, the beta or systematic risk for utility stocks has increased substantially which indicates utility stocks are becoming more volatile, reducing some of their appeal as defensive stocks. For instance, a recent article on Fortune.com titled "Utility stocks are becoming less boring. That's a problem for income investors", the author[10] states:

> Utility stocks are often meant to be a defensive, low volatility, income-producing part of an investment portfolio. In other words, they are boring–and for investors who rely on their portfolio for income, boring is great!
>
> ... As utility companies take on more debt and venture into new business areas, the risk to their investors increases. That risk could translate into suspended dividends, a falling share price, or even bankruptcy. Conversely, companies that remain stagnant risk being left behind.
>
> … The most boring sector in the stock market universe is facing what we tend to associate with high-flying industries like tech: disruption. That may be something to root for when it comes to your fintech or electric vehicle stocks. But when you are depending on an income stream, the last thing you want is disruption.

In addition, in times when capital markets are experiencing significant volatility, many companies, including stable regulated utilities, have more difficulty in raising capital.

In terms of debt capital markets, while certain investors are more attracted to the utility industry in times of volatility, the utility's credit rating is an important factor for investors. Investors would generally not invest in non-investment grade utilities and would be more attracted to A and higher

[10] The author Micheal Joseph is a vice president and deputy chief investment officer at Stansberry Asset Management.

rated utilities. For more details regarding the importance of an A level credit rating especially in "uncertain times", please refer to the response to BCUC IR1 6.4.

7.2 Please provide the Fortis Inc. stock price from 2015 to 2021.

Response:

Fortis Inc. shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE). A primary driver for Fortis Inc.'s financial performance and share price growth from 2015 to 2021 were Fortis Inc.'s US subsidiaries with their higher allowed ROEs. FEI comprises around 14 percent of Fortis Inc.'s asset base and 15 percent of earnings and, therefore, Fortis Inc.'s share price is not a good proxy for FEI's performance.

Fortis Inc. $/Share	TSX (CAD)	NYSE (USD)
3/31/2015	38.58	30.42
6/30/2015	35.08	28.12
9/30/2015	38.17	28.17
12/31/2015	37.41	26.90
3/31/2016	40.71	31.58
6/30/2016	43.67	33.80
9/30/2016	42.19	32.21
12/30/2016	41.46	30.88
3/31/2017	44.07	33.16
6/30/2017	45.58	35.15
9/29/2017	44.78	35.77
12/29/2017	46.11	36.67
3/29/2018	43.49	33.77
6/29/2018	42.02	31.88
9/28/2018	41.88	32.42
12/31/2018	45.51	33.36
3/29/2019	49.39	36.99
6/28/2019	51.71	39.47
9/30/2019	56.01	42.33
12/31/2019	53.88	41.52
3/31/2020	54.27	38.55
6/30/2020	51.63	38.08
9/30/2020	54.44	40.86
12/31/2020	52.00	40.82
3/31/2021	54.53	43.37
6/30/2021	54.87	44.23
9/30/2021	56.19	44.33
12/31/2021	61.03	48.27

7.3 Please describe FBCU's relationship with Fortis Inc. for financing and specifically sourcing equity financing.

Response:

FEI and FBC are wholly-owned subsidiaries of FortisBC Holdings Inc. and FortisBC Pacific Holdings Inc., respectively, which are indirectly wholly-owned subsidiaries of Fortis Inc. FEI and FBC are operationally and financially independent of their ultimate parent; however, they depend on Fortis Inc. to provide equity financing, which Fortis Inc. provides, as required, to maintain FEI's and FBC's capital structures in line with the BCUC established parameters. Fortis Inc. is the only

1 source of equity financing for the FortisBC utilities as FEI and FBC are not publicly traded. FEI
2 and FBC have a good relationship with Fortis Inc. for sourcing equity financing.

3

8. Reference: Exhibit A11, BCUC IR14, page 15; Exhibit B1-8-1, page 5

On page 5 of "FEI - DBRS 2021 Credit Rating Report" in Appendix D-2, DBRS states:

> In July 2020, the provincial government announced the following amendments to GGRR:
>
> - Increasing the amount of renewable gas FEI can acquire from 5% to 15% of system load.
> - Enabling FEI to acquire hydrogen, lignin, and synthesis gas.
> - Increasing the price cap for the acquisition of renewable gas to $31 per gigajoule, indexed to inflation.
>
> DBRS Morningstar notes that these amendments are not material from a credit perspective but will support the Company's transition to a lower carbon economy.

Section 18 (2) of the *Clean Energy Act* states, "In setting rates under the *Utilities Commission Act* for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking."

8.1 Please confirm that the BC Government has introduced provisions requiring FEI to meet a defined threshold for its contributions to GHG reductions in line with the government's GHG reduction targets.

Response:

The provincial government has announced its intention to set a GHG emissions cap (i.e., a defined threshold) on natural gas utilities in the CleanBC Roadmap, although the provincial government has not yet formally introduced legislation or regulations that would require FEI to meet a defined threshold. FEI has been engaging with the provincial government to better understand and inform the direction of the GHG emissions cap. The government has not yet announced the details of its proposed approach, including the timing of the legislation and regulations, the overall nature and mechanics of the policy, or the overall GHG reductions FEI will be required to meet.

8.1.1 Please confirm that, to the extent the regulation enables the required actions to achieve these GHG reductions, FEI will have the opportunity to meet the provincial thresholds and will likely have the capabilities to do this.

Response:

FEI cannot confirm the statement, as uncertainty persists.

The GGRR is likely insufficient in allowing FEI to meet the contemplated provincial GHG emissions cap and other GHG reduction mandates as described in the CleanBC Roadmap. The GGRR allows FEI to acquire up to 30 PJ of renewable gases, and this could lead to a 1.5 Mt reduction of GHGs in the province. However, the CleanBC Roadmap outlines that it is seeking a much larger reduction from natural gas utilities of 5.5 Mt from buildings and industry along with GHG reductions from other sectors. There are different pathways to accomplish this goal which could have different roles for FEI. As described in the response to BCOAPO IR1 5.1, there are competing visions to decarbonization in BC. Without more detail on the policy, the GHG emissions cap for natural gas utilities could limit FEI's opportunity to invest in solutions that meet provincial targets.

8.2 Please quantify the GHG reductions which would be required from 2022 to 2030 to meet the targets, and quantify the quantity of carbon tax cost avoidance or reductions which FEI's customers will avoid, and the future present value for the next 20 years of those reductions in comparison to the FEIs current understanding and estimation of the future cost of implementing the GHG reductions, assuming that the Commission approves FEI's reasonable and cost-effective plans.

Response:

As discussed in responses to CEC IR1 8.1 and 8.1.1, the pathways and mechanisms to achieve carbon reductions to meet the CleanBC Roadmap to 2030 emissions cap are under development. The pathways to meet the emissions cap will include RG as well as other compliance pathways that reduce demand such as demand side management (DSM) and fuel switching of some load to other energy sources such as electricity. Consequently, FEI is unable to determine the cost of all measures required.

Please refer to the response to RCIA IR1 3.9.3 for a discussion of the approximate cost of renewable gas and DSM measures to 2030 enabling GHG reductions.

9. Reference: Exhibit B1-8-1, page 81-82

> Renewable Gas provides an alternative to hydro-generated electricity from an emissions reduction perspective and would meet new code and regulation requirements. However, there is a general lack of awareness and acceptance from customers and stakeholders as to the role Renewable Gas plays in reducing emissions when compared to electricity. The lack of acceptance of Renewable Gas, from customers and stakeholders is largely driven by the perception that is a bridge fuel and potentially not a long term emissions reduction.

9.1 Please discuss whether or not FEI has a plan to make a promotional case to its customers that:

(a) as it progresses to implement RNG with the approval of the Commission and the BC government that the GHG reductions will reach 2030 government targets;

(b) from a cost-effectiveness point of view, the customer will be getting their heating at increasingly reasonable gas costs and avoiding the carbon tax for substantial net benefits for the customers;

(c) will remain in a competitive position compared to alternative heating options based on an electrical system that would need substantial capital additions to its abilities to provide peak capacity and energy to serve heating loads in addition to its role in transitioning the vehicle transportation sector through fuel switching from oil-based fuels to electricity; and

(d) that FEI will continue to be following technology developments to further implement cost-effective solutions to enable the natural gas supply to meet its heating need in full compliance with meeting BC's climate change objectives.

Response:

FEI has been actively working to inform and educate government, customers, the public and other stakeholders on its plans to reduce emissions, including the areas noted in the question above. However, communicating information regarding the benefits of FEI's climate solutions does not guarantee greater acceptance; this includes acceptance of renewable natural gas. For example, please refer to the response to BCUC IR1 15.4 where FEI discusses examples where, despite an awareness of renewable natural gas, there is a preference to use it as a bridge fuel, rather than a long-term emissions reduction energy source.

9.2 Please discuss whatever assistance FEI would need from its regulator and from the BC Government to make it possible for FEI ensure customer awareness and acceptance and be able to credibly advance its energy transition case sustainably for the long term.

Response:

The Energy Transition and reducing GHGs is a complex and challenging topic to convey to customers to gain awareness and acceptance. From a customer and public education standpoint, governments have a key role in explaining emissions targets, what achieving the targets will look like, how it will impact their day to day lives, what changes will be required and how the cost of energy will increase.

Regarding the gas system, FEI believes that government should provide clear direction and support for the key role of the gas system in helping BC achieve its energy and emissions goals. This would include describing how provincial policies support the continued overall use of gas infrastructure and renewable gases, which supports the financial and operational health of the utility. This would include an energy agnostic and equal approach to emissions reducing measures and activities, whether gaseous or electric.

Finally, government should communicate the foundational nature of policies like the GHG Reduction Standard to local governments in an effort to streamline policies and avoid conflicting messages.

10. Reference: Exhibit A11, BCUC IR#16, Q16, Page 17

On page 81 of the FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, FEI states:

> The primary means of mitigating the risk of lower than expected production is to diversify the supply portfolio. Today, FEI has a diverse mixture of supply projects that use different feedstock and technologies and are located in geographically separate areas. This diversity helps to reduce supply volume risks to the portfolio as all projects in the portfolio will not be subject to the same types of risks. As FEI acquires Renewable Gas from new projects, this will diversify the portfolio further and reduce risk. In addition, there are now suppliers that are themselves aggregators of RNG supply, meaning they have a diverse supply of projects within their own portfolio – thereby reducing supply risk. By contracting with these aggregators, FEI may be able to secure a firmer supply, effectively transferring supply risk to the supplier.

10.1 Please provide a quantification of FEI's experience of failures in terms of number of failures and the duration of the failure before RNG supply is returned to its anticipated level, for each of its 10 operational suppliers.

Response:

The table below summarizes typical outages over a one-year period for FEI projects. FEI does not have this data readily available for its other suppliers.

Calendar Year 2021				
	# of Failures	Average Failure Length (Days)	Estimated Quantity of RNG Lost (GJ)	Actual RNG produced (GJ)
Supplier 1	7	11	13,501	38,518
Supplier 2	4	36	4,816	6,053
Supplier 3	8	5	2,597	17,927
Supplier 4	4	3	1,200	40,620
Supplier 5	3	19	15,262	82,470
Supplier 6	10	5	2,653	3,658
Total			40,029	189,246

The total estimated quantity of RNG lost was 40,029 GJ, which comprises 22 percent of the 189,246 GJ of total actual supply from those 6 FEI projects.

10.2 Please provide a quantification of FEI's experience in terms of loss of a supplier in terms of the numbers lost and the quantity of RNG supply lost.

Response:

FEI interprets this question to ask about FEI's overall experience with the expected loss of supplier or the failure of a supplier to provide RNG promptly following agreement execution.

FEI has experienced cases where RNG supply projects have not been developed after BCUC approval and it has experienced significant delays that required contract restructuring.

With respect to lost projects, FEI has experienced a single case of an approved project that never produced RNG – the Earth Renu Project. It represented a maximum production of 205,000 GJ per year. At the time, that accounted for one out of seven approved projects with a volume equal to about 25 percent of the total supply.

Of those initial seven projects, two were delayed significantly and required contractual restructuring. The GVSDD project did not supply RNG for close to eight years and the Dicklands Farm project is expected to have a nine-year delay from the initial approval. Together, these projects represented about 15 percent of the supply at the time of approval.

10.3 Please provide a discussion of FEI's contractual terms for supply, specifically in terms of how the contract deals with failure to supply.

Response:

FEI sets minimum supply volumes in its contracts. The volumes are based upon the expected range of production at a given facility and the potential increase in supply over time. The volumes are typically monthly and annual volumes. The ranges between minimum required volumes and maximum volumes are negotiated.

In the event that a supplier does not meet the volumes, the contracts vary on potential consequences. In all cases, FEI may terminate the agreement when a supplier fails to meet the minimum volume commitment.

In some cases, FEI has the option to secure additional RNG supply on its own along with associated payments by the potential supplier.

In the event of termination FEI is entitled to a termination payment. The termination payment along with the loss of payments (due to lack of supply) provide a strong incentive for suppliers to meet minimum requirements. There is also an incentive to reach maximum because suppliers will receive higher revenues annually.

Regardless of any financial compensation, FEI would still be potentially short of physical gas supply and the associated environmental attributes in the event that it cannot quickly find

alternative sources. Therefore, in the event of supply failure, FEI still has a risk of falling short of its energy delivery requirements as well as its GHG reduction commitments such as the provincially mandated Greenhouse Gas Reduction Standard where FEI will be obligated to operate below a pre-determined GHG emissions cap.

10.4 Please confirm that the natural gas supply to customers is not impacted when a failure to supply RNG occurs because the RNG process of dealing with GHG reduction is notional and disconnected from physical supply.

Response:

Any RNG supplied inside the province may impact the total amount of actual gas in the system. However, at current levels FEI can make up these volumes with conventional supply if necessary. Similarly, RNG from out-of-province still has a physical component supplied to FEI.

With respect to emissions reductions, a failure to supply RNG would impact the environmental attributes because there is less RNG in the system to sell and therefore the environmental attributes are not available to FEI or its customers.

10.5 Please confirm that compensating for failures in supply is primarily a function of contracting for additional growth in supply, which FEI is planning to do under any circumstances and therefore it involves potential timing delay in meeting targets and can be managed by managing the growth pace.

Response:

FEI interprets this question as asking whether the solution to supply failures is to contract for additional supply. With this clarification, FEI confirms that this will be the primary mechanism to address supply risk. If FEI experiences a failure in supply additional RNG supply contracts could be added.

10.6 Please provide FEI's potential options as new technologies develop for replacing RNG with other GHG reducing options, and specifically with even longer-term and more reliable potential.

Response:

FEI continues to see RNG potential. RNG will be augmented rather than replaced as the technology advancements enable a broader range of feedstocks that can be used to grow supply.

The recently released British Columbia Renewable Gas Potential Study[11] shows that there is significant potential in British Columbia to produce new alternative supplies of renewable and low-carbon gases including for example hydrogen. Hydrogen production methodologies based on methane reforming and methane pyrolysis including carbon capture and storage present significant potential to scale and produce low carbon-intensity hydrogen at lower cost, and without straining the electricity system, compared to electrolytic (green) hydrogen production methods.

Please also refer to the response to CEC IR1 5.4 where supported low-carbon hydrogen projects are listed.

10.7 Please confirm that while there may be issues and concerns to deal with FEI expects to have the capacities and capabilities to manage its path to creating its case for meeting GHG reductions and contributing substantially to the provincial Clean Energy plans and targets.

Response:

As stated in the question, there are many issues to be dealt with in meeting and contributing to the provincial Clean Energy plans and targets, but FEI has a plan in place to do so.

Although FEI has shown that it has been able to innovate and develop the capabilities and capacity to develop its response to the provincial GHG aspirations and move toward achieving its targets, it is important to understand that the path is new and has not been implemented to the extent envisioned in CleanBC by any gas utility in the world to date. There are challenges and technology risks that mean that the plan could materialize in different ways than currently envisioned.

Further, as discussed in Concentric's evidence (Appendix C) investors perceive risk to this new pathway:

> Achieving net zero GHG emissions by any date is a tremendous challenge for a natural gas distribution utility, FEI included. There are two commonly identified fuel alternatives for gas distribution utilities to comply with net zero targets:

[11] https://www.cdn.fortisbc.com/libraries/docs/default-source/news-events/bc-renewable-and-low-carbon-gas-supply-potential-study-2022-03-119b1624d693c7435ebcd416b13869f7a8.pdf?sfvrsn=1ed16720_0

hydrogen and renewable natural gas ("RNG"). However, pursuing those pathways carries risk from an investors' perspective. …

Thus, while RNG and hydrogen may offer a potential pathway for FEI through the Energy Transition, investors perceive significant risk to that pathway because of its operational, technical, and financial challenges.

10.8 Please confirm that natural gas production and natural gas wells also have failure modes and have uncertainties in their life supply timeframes but that ensuring an abundance of supply to offset risks, works for the natural gas industry but does not prevent failures and maintenance issues from complicating supply from time to time, which can be reflected in market prices.

Response:

Confirmed. Natural gas wells can be faulty and some can be frozen shut by cold weather. This would reduce natural gas production for a short time period and can be reflected in daily market prices. Due to the abundance of natural gas supply, there would have to be a significant shut down for a longer period of time to make a larger impact on market prices overall.

11. Reference: Exhibit B1-8-1, Appendix A, page 119-120

> Further, due to the uncertainty around the future role of natural gas in BC's energy infrastructure, FEI's capital intensive CPCN projects are also facing a higher level of regulatory uncertainty such that the BCUC may be hesitant to approve projects that add to the system capacity and lead to higher rates. This, in turn, will impact FEI's ability to adapt to a low carbon environment.
>
> …
>
> One aspect of regulatory lag is the time between BCUC application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and when the final order related to that application is issued. While
>
> …
>
> FEI believes that, compared to the 2016 Proceeding, the risk associated with regulatory lag has experienced a notable increase. FEI has observed increased interest and active participation by Indigenous and environmental groups in regulatory proceedings, such as its CPCN applications

11.1 Please confirm that regulatory processes and lags for a variety of reasons have always been possible and from time to time have occurred, and should be expected to occur.

Response:

FortisBC agrees that regulatory processes and lags have always been possible and have occurred from time to time, and regulatory risk has consistently been identified as a risk factor for FortisBC in past cost of capital proceedings. As FortisBC has stated in its evidence (and as quoted in the preamble), FortisBC believes that, compared to the 2016 Proceeding, the risk associated with regulatory lag has increased.

There are a number of examples of increased regulatory lag since the 2016 Proceeding and the increased lag is due to a variety of factors, which FortisBC has described in its evidence.

FortisBC has observed a change in how routine filings are reviewed since the 2016 Proceeding. For most applications, there is now a public review process or at a minimum an opportunity for public involvement through, for example, letters of comment; whereas, in the past, routine filings could proceed to a BCUC decision with either no process or with a small number of IRs from BCUC staff. Irrespective of the merits of this new approach, one result of this change is that smaller applications are now generally taking longer to receive BCUC approval, which increases regulatory lag. Examples of these filings include:

- Operating agreements;
- CNG/NGT fueling service rates and agreements under the GGRR; and
- Amendments to tariffs and rate schedules.

11.2 Please confirm that if FBCU, and FEI in particular, is concerned with potential lags in certain Commission decisions, it has in the past asked the Commission for decisions by particular timelines and that the Commission has for the most part done all that it is capable of to accommodate utility requirements.

Response:

FortisBC agrees that the BCUC has made its best efforts to accommodate timelines for decisions when requested. There are, however, many factors that can extend timelines. For example, a requirement to have more public process can preclude short timelines. The BCUC's own resource constraints, arising from a vastly greater case load, can lead to scheduling challenges. Factors such as the larger number of parties being involved in proceedings, the complexity of applications, and large numbers of information requests can lead to the need for timelines to be extended, whether at the request of the applicant or other parties. In some project hearings, special processes have been established to take evidence from Indigenous groups.

FortisBC wishes to be clear that it is not commenting on the need for, or appropriateness of, such extensions and processes. Rather, FortisBC is making the observation that these processes and extensions can give rise to risk for FortisBC in the form of regulatory lag.

11.3 Please confirm that FBCU and FEI always have the ability to advance their potential filing timelines to ensure that they get decisions in the required timeframe.

Response:

FortisBC agrees in part. As described below, the influence of factors beyond FortisBC's control has increased.

FEI and FBC have generally been able to manage potential filing timelines to ensure as best as possible that BCUC decisions are issued in the timeframe required by the utilities because traditionally FEI and FBC have been in control of most of the aspects involved in preparing the projects and applications. For instance, FEI and FBC have internal processes in place that guide the preparation and filing timelines for revenue requirement and rate design applications and, even once filed, the applications tend to follow similar review processes, so it has generally been possible to receive decisions by the utilities' requested dates. This has also historically been the case for FortisBC's CPCN projects, as FortisBC would identify the need for the project internally and would prepare a project schedule which included both the time needed to prepare the application internally and the time estimated for the regulatory review process so that a decision is received and the project constructed by the identified need date.

As explained in FortisBC's evidence, the complexity of FEI's and FBC's operating and regulatory environments has increased, which has resulted in a number of different factors that increase the length of regulatory processes and reduce the amount of control that FortisBC has over when it can file an application and how long a regulatory process might take. For instance, the number of renewable gas applications filed by FEI has increased in the past couple of years and will continue to increase as FEI seeks to meet its GHG reduction targets. FEI competes with other companies to acquire supplies of RNG and for CNG/LNG customers, and there are negotiations that need to take place in advance of filing for BCUC approval. The length of these negotiations depends on the actions of the counterparty, which impacts when FEI is able to file for BCUC approval. Further, the third parties that FEI is negotiating with often require that an agreement be finalized by a certain date, and that the finalization be contingent on BCUC approval, which has led to situations where FEI must request highly expedited review processes and/or request approval of interim rates and agreements.

With regard to CPCN projects, there are a number of factors which are causing increased uncertainty regarding regulatory timelines and these factors are, to an increasingly greater extent, outside of FortisBC's control. For instance, there is a greater need for early engagement with Indigenous Nations, the progress of which can depend on the availability and institutional capacity of the Indigenous groups. Other factors include the requirement to obtain approval through more robust parallel processes to the BCUC's process (e.g., the Environmental Assessment process for projects such as the TLSE project) and the increased complexity and requirements around engagement and consultation (e.g., the OCU project). Even projects which, on their face, might have been expected to be more "routine" and therefore the regulatory process be easier to predict, are now subject to a broader range of considerations and, therefore, extended regulatory processes. A recent example of this is the FEI Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) project. The application review process had originally been envisioned to wrap up in late November 2021; however, in February of this year, the evidentiary record was re-opened when the BCUC Panel filed a round of IRs seeking information on FEI's medium and long-term forecasts regarding hydrogen and the impact of these forecasts on the CTS TIMC project.

In addition to the factors discussed above, the number of parties intervening in FortisBC's regulatory processes has increased and, in particular, there has been an increase in the number of "non-traditional" interveners. The increased level of active participation in regulatory processes can cause delays to the overall timetable due to: the need to increase the length (and breadth) of public notice periods; the increased instances of late intervener registration which require timetable extensions; the increase in the number of IRs and the length of time required both for parties to ask IRs and for FortisBC to respond to IRs; and the increased desire by some interveners to file intervener evidence. While aspects of these increased regulatory timelines can be managed by FortisBC through earlier filing of applications, as discussed previously, the timing of filing applications is less often in FortisBC's control.

11.4 Please confirm that it is the utility's responsibility to ensure that its regulatory filings are sufficiently timely to meet the utility needs, and sufficiently well-developed to allow for prompt and thorough review.

Response:

Confirmed that it is the utility's responsibility to ensure its applications are sufficiently well-developed, and to bring them forward as early as reasonably possible. As described in the response to CEC IR1 11.3, the timing can nonetheless be affected by factors beyond the utility's control. Further, the extent of review and the number of parties involved has resulted in longer review timelines.

These factors are described in the responses to CEC IR1 11.1 through 11.3, and are outside of FortisBC's control.

11.5 Please identify the number of decisions sought each year sought by FEI and sought by FBC which have not reached a reasonably successful approval decision for FBCU on a reasonably appropriate timetable.

Response:

FortisBC considers the issues of receiving a reasonably successful approval decision and receiving a decision (reasonably successful or otherwise) on a reasonably appropriate timetable as separate and distinct risk factors.

In situations where FortisBC's applications have been denied by the BCUC (either in whole or in part), if FortisBC considered the decision meets the criteria for reconsideration, FortisBC would seek this remedy. The length of the proceeding which resulted in such a decision would not likely factor into FortisBC's rationale for applying for reconsideration and/or variance. FortisBC generally finds the BCUC's decisions to be well reasoned (irrespective of whether a decision is favourable to FortisBC or not), thus there are limited examples where FortisBC has reconsidered a BCUC decision. Examples of reconsiderations filed by FortisBC include the 2014-2019 PBR Plan Decisions (FortisBC reconsidered three specific aspects of the decision), the BCUC's decision on FortisBC Energy Utilities' (FEU) Common Rates, Amalgamation and Rate Design Application (the original application was denied by Order G-26-13), and the FBC Net Metering Program Tariff Update Application (reconsideration of Order G-199-16).

FortisBC believes that trying to assess timing of decisions on the basis of whether it is "reasonably appropriate" is not useful:

- First, FortisBC considers the assessment of "reasonably appropriate" to be highly subjective.
- Second, and more importantly, in identifying increased regulatory lag as a risk factor, FortisBC is not commenting on the merits of holding longer processes. There are factors which can impact the length of a regulatory timetable which are beyond anyone's reasonable control. Additional process steps also may well be appropriate from the standpoint of procedural fairness and ensuring a complete evidentiary record. FortisBC's point is that, regardless of the cause of longer processes, the delay does present a risk.

However, to be responsive, FortisBC provides the following examples of applications where there have been lengthy regulatory processes. These examples are in addition to the examples provided in FortisBC's evidence, such as the Okanagan Capacity Upgrade and the Tilbury LNG Storage Expansion projects, as described on page 120 of Appendix A and in the response to BCOAPO IR1 10.3.

- FBC Self-Generation Policy – this proceeding commenced on January 19, 2015 when FBC filed its High Level Self-Generation Policy Application in response to directives contained in the BCUC's reasons for decision related to Orders G-60-14 and G-67-14. The BCUC issued its "Stage I Decision on March 4, 2016" which directed FBC to file a "Stage II Self-Generation Policy Application". FBC filed the Stage II application on November 10, 2016 and a decision on this application was issued on February 27, 2019. Accordingly, this proceeding spanned over four years.
- FEI 2017 Price Risk Management Plan (PRMP) – on June 13, 2017, FEI applied for approval to extend the term of the PRMP and adjust the hedging price targets for the medium term fixed-price hedging strategy already approved by Order E-10-16, as well as approval for a longer term fixed-price hedging strategy based on pre-defined market price targets. FEI requested an expeditious review of the medium-term hedging adjustments so that FEI would be in a position to capture any market opportunities for terms from Winter 2017/18 out to Summer 2020. On August 25, 2017 (by Order G-133-17), the BCUC issued a regulatory timetable and reasons for decision which sought submissions from interveners on the proposed scope of the proceeding and the preferred review process. Subsequent to receiving the submissions, the BCUC issued Order G-168-17 on November 23, 2017 determining that the scope of the application should include addressing the foundational questions set out in Order G-133-17. As a result, the BCUC directed FEI to file a revised application and/or addenda addressing certain topics by January 5, 2018, at which time, the regulatory process for the application would be determined. Ultimately, a decision on the 2017 PRMP was not reached until May 22, 2019, almost two years after the initial application.
- FBC Rate Design and Rates for Electric Vehicle Direct Current Fast Charging (EV DCFC) Service – FBC originally filed this application on December 22, 2017, proposing to set its EV Charging rates under traditional cost of service principles. The BCUC then adjourned the proceeding on January 12, 2018 by Order G-9-18 and initiated the EV Charging

Service Inquiry, which lasted until mid-2019. The BCUC then restarted the review of FBC's EV DCFC Service application on July 10, 2020 subsequent to the BC government issuing Order in Council (OIC) No. 339 amending the GGRR to add EV charging stations as prescribed undertakings. The application review process restarted in July 2020, and the BCUC issued its final decision approving permanent EV rates on November 30, 2021, almost four years after the initial filing.

- FEI Biogas Purchase Agreement between FEI and the City of Vancouver – FEI originally filed this application on September 21, 2018 seeking acceptance of a BPA pursuant to section 71 of the UCA with the City of Vancouver, a prescribed undertaking under the GGRR. FEI anticipated that this application would be reviewed and approved within a few months, consistent with how previous BPA projects had been reviewed and approved by the BCUC. However, on November 16, 2018, the BCUC established a public hearing process to review the application which included one round of IRs and a procedural conference.[12] Ultimately, the regulatory process involved two rounds of written IRs, a procedural conference and a Streamlined Review Process, culminating in a decision being issued by the BCUC a year after filing, on September 27, 2019.

11.6 Please prepare the yearly statistics for FBC or FEI applications which have not reached a reasonably successful approval decision for FBCU on a reasonably appropriate timetable, divided by the number of applications for the year.

Response:

FortisBC cannot provide a meaningful statistical analysis due to the subjectivity of the concepts in the question and the various legitimate considerations that could impact the duration of a proceeding. Please refer to the response to CEC IR1 11.5.

11.7 Please quantify the risk impact FBCU or FEI have incurred because of any regulatory decisions which FBCU and FEI claim have not reached a reasonably successful approval decision for FBCU on a reasonably appropriate timetable.

Response:

Regulatory risk associated with the uncertainty around regulatory approvals and regulatory lag is not a quantifiable risk event but rather something that is considered by investors in their qualitative risk assessments. For instance, Moody's rating methodology gives 12.5 percent weight to the

[12] Order G-219-18.

"timeliness of recovery of operating and capital costs" and another 12.5 percent to the "consistency and predictability of regulation". To FortisBC's knowledge, both of these rating sub-factors are mainly rated qualitatively.

11.8 Please provide a list of all of the regulatory processes which are beneficial to FBC and FEI, and to which many natural gas utilities in other jurisdictions may not have access.

Response:

FortisBC assumes that a "beneficial" regulatory process would be one that is aimed at shortening the length of a regulatory process; however, FortisBC notes that efficient regulatory processes are also beneficial to customers, as they generally result in lower regulatory proceeding costs and therefore less pressure on customer rates.

The BCUC has developed certain regulatory processes over time that are innovative and have allowed for more efficient review processes. An example of this is the Streamlined Review Process (SRP). FEI's annual review process for setting delivery rates is also more efficient than utilities that are under cost of service rate-setting regimes in BC, although FortisBC still undergoes a fairly fulsome public review process annually to set delivery rates under the MRPs. The use of Negotiated Settlement Process (NSPs), potentially as an efficient process, remains an option but its use has declined in BC in recent years.

FortisBC has not done research on the regulatory regimes and practices throughout North America so as to permit an informed comparison. FortisBC is aware that NSPs are used in other jurisdictions, as are multi-year rate plans. FortisBC also notes that Mr. Coyne considers BC to be a generally favourable regulatory environment for utilities. Concentric has considered regulatory regimes in the context of selecting proxy groups of comparable risk.

11.9 Please confirm or otherwise explain that credit rating agencies consider the BC utility regulatory environment stable, fair, and favourable to the utilities.

Response:

Both Moody's and DBRS consider BC utility regulatory environment to be stable. Moody's and DBRS did not comment on whether they consider the regulatory environment to be fair or favourable to the utilities.

In addition, DBRS considers regulatory risk one of the four main challenges for FEI. As noted in the 2021 DBRS credit rating report dated January 5, 2022 for FEI:

> As a regulated utility, the regulated operations of FEI are generally subject to some uncertainties, including the following factors: (A) The ability of the Company to recover the actual costs of providing services and to earn the approved rates of return is affected by achieving the forecasts established in the rate-setting process; (B) capex for system upgrades and new facilities requires the approval of the BCUC for inclusion in the rate base. There is no assurance that capital projects perceived as required by FEI will be approved; and (C) the BCUC sets the ROE and deemed capital structure. Currently, the Company's allowed ROE is 8.75% and its component of common equity is 38.5% until otherwise determined by the BCUC. There is no assurance that the rate orders by the BCUC will allow FEI to recover all actual costs incurred and earn the expected or fair return. DBRS Morningstar expects the BC regulatory framework to remain stable. Any regulatory decision by the BCUC that may have a material negative impact on the Company's earnings and cash flow could result in a negative rating action.

Similarly, in its 2021 credit rating report for FEI dated November 25, 2021, Moody's noted that while FEI operates in the credit supportive regulatory environment of British Columbia, an adverse regulatory decision can lead to a credit rating downgrade.

12. Reference: Exhibit B1-8-1, Appendix C, page 105

> FEI discusses specific aspects of regulatory risk related to the Company's most recent PBR plan in its risk evidence. More generally, PBR is viewed as posing greater risk on the utility since the ability to earn the allowed return is dependent on achieving preset productivity gains. In DBRS's
>
> …
>
> I assess FEI's regulatory environment as generally favorable from an investor's perspective, but agree with FEI that the risk related to PBR is somewhat higher due to certain changes in the 2020-2024 PBR plan compared to the prior plan, an increase in regulatory lag for large infrastructure projects, and uncertainty regarding regulatory support for FEI's actions for managing the Energy Transition.

12.1 Please provide quantitatively for each year in the FEI's history since 2012 to 2021 with respect to its actual return on investment versus the allowed return on investment and document for each year the form of regulation under which FEI was operating.

Response:

Please refer to the following table which contains the actual and approved return on equity since 2012 for FEI. 2021 actual results are not yet available and will be filed April 30, 2021 in the 2021 FEI BCUC Annual Report, so they are not included in the table below.

FEI - Return on Investment

Years[1]	Allowed	Actual Pre-ESM	Actual Post-ESM[2]	Form of Regulation
	(a)	(b)	(c)	
2012	9.50%	10.12%	-	Cost of Service
2013	8.75%	9.13%	-	Cost of Service
2014	8.75%	9.54%	9.20%	PBR
2015	8.75%	9.51%	9.19%	PBR
2016	8.75%	9.65%	9.28%	PBR
2017	8.75%	9.25%	9.04%	PBR
2018	8.75%	8.99%	8.93%	PBR
2019	8.75%	8.79%	8.85%	PBR
2020	8.75%	8.87%	8.81%	MRP

Notes:
[1] 2012 - 2014 amounts are FEI pre-amalgamation; 2015 - 2020 reflects the amalgamation of the Vancouver Island and Whistler utilities with FEI.
[2] 2012 and 2013 Post-ESM not applicable as no Earnings Sharing Mechanism was approved.

12.2 Please provide for each year from 2012 to 2021, which of each of the following aspects of regulation FEI accessed:

(a) earning sharing;

(b) off ramps;

(c) deferral accounts;

(d) Z factor;

(e) annual review confirmation of rates;

(f) GISMIP earnings; and

(g) cost flow through to rates outside of earning sharing.

Response:

Please refer to the table below which shows each of the noted items that were applicable to FEI and that impacted rates in some form or another from 2012 to 2021.

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
a) Earning Sharing			✓	✓	✓	✓	✓	✓	✓	✓
b) Off Ramps										
c) Deferral Accounts	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
d) Z-factor								✓ (See Note 1 below)		
e) Annual Review Confirmation of Rates	See Note 2 Below	See Note 2 Below	See Note 3 Below	✓	✓	✓	✓	✓	✓	✓
f) GSMIP Earnings	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
g) Cost flow-through to rates outside of earning sharing (See note 4 below)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Notes:

1. Z-factor treatment was approved as part of the 2019 Annual Review[13] for the 2019 Employer Health Tax and 2018 and 2019 Medical Service Plan (MSP) premium reductions.
2. The delivery rates for 2012 and 2013 were approved as part of a two-year cost of service revenue requirement application pursuant to Order G-44-12.
3. The 2014 delivery rates were approved by Order G-138-14 as part of the 2014-2019 PBR Plan Decision.
4. During both the 2014-2019 PBR Plan term and the current 2020-2024 MRP, FEI is approved to flow-through certain costs and revenues outside of the earnings sharing mechanism, such as property taxes, Clean Growth initiatives and sales revenue. While FEI was not subject to an earnings sharing mechanism in 2012 and 2013 as FEI's rates were set based on cost of service, FEI still flowed through certain revenues and costs through the use of deferral accounts (e.g., RSAM deferral account, application cost deferral accounts) for the purpose of ensuring that customers were held whole (i.e., to ensure that customers only paid for the actual costs, not the forecasts). All deferral accounts are reviewed and approved by the BCUC. FEI also notes that depending on the amortization period of each deferral account, some of the actual costs might be flowed through to rates over multiple years.

[13] Order G-237-18.

13. Reference: Exhibit A11, BCUC IR24, Page 26

On page 1 of Exhibit B1-8, FBCU states, "FortisBC seeks …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."

On page 2 of Exhibit B1-8, FBCU states, "The overall return must reflect the business risks facing FEI and FBC that define the potential risks and uncertainties that each company faces in achieving a Fair Return on and of invested capital in both the short and long-term."

On page 17 of Exhibit B1-8, FBCU states, "FBC's overall business risk is similar to what was assessed in the 2013 Proceeding."

The GCOC (Stage 2) Decision and Order G-47-14 on page 60 states, "FBC proposes a 40 percent common equity ratio with an ROE risk premium of between 50 and 75 bps."

13.1 Please confirm that given the provincial initiatives for electrification of vehicle transportation, and electrification as fuel switching for other sectors of the economy, that FBC in fact has less risk with respect to its customer base and demand volumes in this regard.

Response:

Please refer to the response to BCUC IR1 31.1.

14. Reference: Exhibit B1-8-1, Appendix B, page 19

> FBC purchases approximately 18 percent of the energy and 18 percent of the capacity required to serve its customers from BC Hydro under the PPA at rates contained in BC Hydro Rate Schedule 3808 (RS3808)[20]. The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's customers. This means that cost competiveness with other forms of energy and other providers can be worsened by un-negotiated increases, if introduced, in the PPA rates when and if approved by the BCUC.
>
> BC Hydro has indicated that it anticipates a general rate decrease of 1.4 percent, effective April 1, 2022, followed by an increase of 2.0 percent, effective April 1, 2023, and an increase of 2.7 percent, effective April 1, 2024.[21] FBC does not have any indication or certainty regarding future BC Hydro rate increases beyond March 31, 2025, which would affect Tranche 1 energy and capacity rates.

14.1 Please confirm that BC Hydro has an energy surplus for a considerable period of time into the future and will potentially be making energy available in the electricity markets at rates that could be favourable to FBC.

Response:

FBC can confirm that BC Hydro currently expects to have an energy surplus for several years as presented in their recently filed 2021 Integrated Resource Plan (IRP). As BC Hydro is almost solely reliant on water availability, any actual surplus in any given year will depend upon water availability as well as actual loads. If BC Hydro is in a surplus situation, FBC agrees that BC Hydro may potentially be making energy available in the electricity markets. FBC expects that the price at which this energy could be available will be determined by market prices at the time of the surplus.

Under the CEPSA agreement with Powerex, FBC does not determine the source of its market purchases and does not know if any BC Hydro surplus would be sold to FBC or not. Cost is not the only consideration for FBC market purchases. FBC buys the majority of its market energy through monthly blocks rather than on the day ahead or hourly markets. If BC Hydro surplus is to be sold to FBC, these considerations must also be met.

14.2 Please confirm that the costs for wind and solar energy are declining substantially from prior cost levels and are reducing the risks for electric utilities of higher marginal costs for energy in the future.

Response:

FBC confirms that the cost for wind and solar energy have made substantial declines from prior levels and that it is expected that further cost declines will occur. This is, of course, at least partly

subject to the price of steel and other raw materials that are required. However, these resources do not provide reliable capacity and, as such, the declines in the cost of the energy they produce simply shifts the risk to capacity. Traditional generation resources such as hydro, coal, gas and nuclear come with dependable capacity as well as energy. If anything, capacity risk is higher for electric utilities than it used to be. This is illustrated in the response to BCUC IR1 34.1 where it is shown that, if the BC Hydro PPA is not renewed, the FBC portfolio LRMC can vary between $87 and $157 per MWh depending on the available resources to replace the lost capacity.

14.3 Please confirm that BC Hydro has had a number of EPAs which it has been and will be considering renewing, and will likely be renegotiating these contracts with market-based influence on the pricing.

Response:

FBC agrees that BC Hydro states in its recently filed 2021 IRP that it has a number of EPAs which it expects to consider renewing using market-based pricing. The majority of these projects are located within the BC Hydro service area. If FBC were to attempt to purchase any of this power, BC Hydro wheeling charges would apply, likely making any FBC offer non-competitive. However, it is possible that some of this power may be available to FBC if agreement on price can be reached.

14.4 Has FBC been in contact with any of the independent power producers BC Hydro is not planning to renew and/or has FBC been in contact with BC Hydro in terms of a price for power which may be surplus to BC Hydro for the next 10 years? Please explain.

Response:

As stated in FBC's recently filed LTERP,[14] there may be opportunities for FBC to acquire power from expiring EPAs on a cost-effective basis in the future. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities. However, price is not the only consideration as the available resources must also provide power at the time FBC requires it. FBC has contacted one independent power producer (IPP) within BC who was not selling to BC Hydro but was not able to arrange a purchase of power.

[14] 2021 Long-Term Electric Resource Plan and Long-Term Demand-Side Management Plan - BCUC, Exhibit B-1, Section 10.6, Page 171.

FBC has not discussed a price/rate for the surplus sale of power to FBC by BC Hydro. Under the CEPSA agreement, Powerex is free to move any surplus BC Hydro power to FBC provided it meets FBC needs at the time. Such a sale would be at a market-based rate.

14.5 Has FBC been in discussion with BC Hydro about its PPA in order to reduce the risks related to obtaining supply from BC Hydro for a future period of time? Please explain.

Response:

FBC has not yet approached BC Hydro to discuss the potential renewal of the PPA and what expanded terms to increase FBC's access to energy and capacity may be possible. FBC plans to approach BC Hydro in 2023 at the half way mark of the PPA to begin reviewing a potential PPA renewal.

14.6 Please confirm that BC Hydro's IRP is currently on the record with the BCUC and provides information with respect to the potential demands and sources of supply along with potential costs of supply information, which can lead to reasonable estimations of BC Hydro's cost of service and future rates.

Response:

FBC confirms that BC Hydro's 2021 IRP is currently on the record as filed with the BCUC and provides information with respect to the potential demands and sources of supply along with potential costs of supply information. The BC Hydro IRP is currently undergoing a review process and it has yet to be determined if estimates of BC Hydro's cost of service and future rates can be determined.

15. Reference: Exhibit B1-8-1, Appendix B, pages 28 and 29

> FBC assesses that compared to 2013, its risks associated with loss of demand in Wholesale and Industrial load is unchanged. The situation regarding the ability of Wholesale and some Industrial
>
> …
>
> FBC currently has four[32] municipal Wholesale customers, accounting for less than one percent of FBC's total customer base, but these four customers make up 17 percent of FBC's load. A loss of any or all of the Wholesale customers to a competing electricity supplier would have a large impact on FBC. If FBC's Wholesale customers elected to discontinue taking service from FBC and pursue any of the opportunities for supply discussed below instead, the loss of their load would result in a reduction of over $51 million in revenue and a substantial rate increase of approximately 6.8 percent for FBC's remaining customers.
>
> As mentioned above, FBC's Wholesale customers have a number of options that would allow them to discontinue taking service from FBC. These include building their own generation to serve some or all of their load, purchasing electricity on the open market or taking service from BC Hydro through its OATT. FBC's Wholesale customers qualify as Eligible Customers as defined under both FBC's OATT and BC Hydro's OATT, and therefore can purchase electricity from the open market or from BC Hydro and wheel over FBC and BC Hydro transmission infrastructure. There is generally available transmission capacity on the transmission system, so access to transmission capacity is not a barrier to FBC's Wholesale customers discontinuing service.
>
> The risk of any or all of FBC's Wholesale customers discontinuing FBC's service increases when some of the following factors are present: FBC's electricity rates increase and the electricity prices on the open market remain competitive; BC Hydro's rates remain lower than FBC's; and, the economics of alternative energy (including, but not limited to, natural gas, distributed generation such as solar and wind power and battery storage) improve. Additionally, all the service agreements between FBC and its Wholesale customers have early termination clauses, allowing FBC's Wholesale customers to exit FBC's service by providing notice.

15.1 Please confirm that virtually all of the opportunities available to FBC's wholesale customers are available to FBC's own generation, purchasing energy on the open market, taking service from BC Hydro through its OATT, or wheeling energy purchases over other utility transmission infrastructure.

Response:

FBC is able to acquire power through any of the means noted and optimizes these resources in order to best meet the needs of its customers. It does not do so, however, on the same terms that benefit Wholesale customers. Most notably, the Access Principles Settlement Agreement (APSA) provides that Eligible Customers may return to embedded cost service and embedded cost rates subject to the Re-entry Provisions it contains, effectively providing a pricing cushion and risk mitigation that is unavailable to FBC.

15.1.1 Consequently, why would FBC have a wholesale rate for which it could not retain these Wholesale Customers?

Response:

The fact that Wholesale customers have rights under the APSA does not remove FBC's obligation to serve customers within its service area. The Wholesale rates are based on the cost to serve the Wholesale customers given industry standard methodologies and based on the current characteristics of the class as a whole.

15.2 Please confirm that FBC monitors the potentials for all customer classes that are cost-effectively competing with FBC and or dropping load served by FBC.

Response:

FBC is not entirely clear on the meaning of, "…customer classes that are cost-effectively competing with FBC", but can confirm that it monitors the actual load of all customer classes against forecasts on an ongoing basis.

15.3 Please confirm that FBC would have regulatory capabilities for managing any risks it anticipates evolving.

Response:

FBC assumes that the question refers to risks attributable to the potential exit from embedded cost service by a Wholesale customer. The rights and obligations with respect to the APSA, including those intended to mitigate against risk to both Eligible Customers and those customers that remain on utility service, are incorporated in the agreement. However, the risks to FBC's other customers due to the drop of a significant amount of load, including rate increases that cannot be fully mitigated through adjustments to the power supply portfolio, cannot be fully eliminated. The business risk to FBC ensues from the situation where eligible customers leave embedded cost service, resulting in increased rates for those that remain, which provides further incentive for additional customers to seek alternate sources of supply.

15.4 Please comment on the potential risks that a small wholesale electric distribution utility could face trying to replace FBC's historic cost-based electricity supply and transmission infrastructure.

Response:

The risk to a wholesale electric distribution utility that elects to leave embedded cost service for a portion or all of its load is primarily related to the cost of alternate resources. FBC assumes that each utility would assess this risk in making resourcing decisions. This risk is mitigated somewhat through the Re-entry provisions of the APSA, which provide that an Eligible Customer that has previously taken bundled service may, at any time, return to power service from FBC at a rate calculated to ensure Fair Treatment (as defined therein), subject to certain conditions including that FBC will make reasonable efforts to accommodate returning Eligible Customers as quickly as possible at rates reflecting the embedded cost of service within either the lesser of the period in which FBC can adjust its supply portfolio or two years from the date of their notice to return to FBC supply.

16. Reference: Exhibit B1-8-1, Appendix B, page 41

> purchased power. FBC has long-term supply contracts with BC Hydro, Columbia Power Corporation, Brilliant Power Corporation and Waneta Expansion Power Corporation. These resources are sufficient to meet FBC's expected[38] capacity requirements until 2030 given the expiry of the Residual Capacity Agreement and FBC's ability to ramp up BC Hydro PPA nomination, despite the expiration of the Brilliant Expansion Agreement in 2027. More significantly, the PPA, under which FBC has firm power supply access to capacity and energy at BC Hydro's embedded costs, expires in 2033. At this time, there is uncertainty that FBC will be able to renew these agreements and at similar costs. If FBC is not able to renew these agreements at similar costs, it may be required to enter into contracts with higher costs or require more costly resources which would increase rates for customers.

16.1 Please discuss the role the interior of BC, and in particular the Columbia River as part of the two-river policy, has played in providing the low embedded cost of power, which BC Hydro customers enjoy.

Response:

FBC is a customer of BC Hydro and therefore has access to BC Hydro power under the BC Hydro PPA. As a customer, except in the most general of terms, FBC is not able to explain the workings of the BC Hydro system. However, in general, the BC Hydro system is a hydro-based system with an extensive storage system on both the Peace River and the Columbia River. Hydro-based generation is capital cost intensive but low cost to operate on an annual basis. One of the major risks of a hydro-based system is a lack of water. In BC Hydro's case, this is partially mitigated by the large storage reservoirs and the fact that the generation is located on separate river systems with separate water availability.

16.2 Please describe why the PPA with BC Hydro has a limited term and requires renegotiation and does not have a permanence based on the historic contributions to providing low-cost hydro power in British Columbia.

Response:

FBC believes that the BC Hydro PPA represents FBC's share of the BC Hydro Heritage system and that FBC is entitled to such power. However, the relationship between FBC and BC Hydro is complex and there is no guarantee that FBC will continue to enjoy access to PPA power from BC Hydro. The terms and conditions under which FBC receives the PPA power need to be reviewed from time to time. Extensive changes were made in 2013 when the PPA was renewed at that time and FBC anticipates that further changes may be required in 2033 depending on the circumstances at the time. Such changes may include, but are not limited to, the right of FBC customers to export customer-owned generation while taking supply from FBC, the right of FBC to export surplus power from FBC-owned or contracted-for generation while taking supply from BC Hydro, the volume of power under the PPA that FBC is entitled to and the right of FBC to

import intermittent power such as from solar and wind[15]. These are fundamental questions relevant to the PPA that will only get more complex as the generation resource mix changes over time.

16.3 Please discuss the Columbia River Treaty and the Downstream Benefits that have accrued to the province of BC as a consequence of providing flood control and installation of power generation on the Columbia and co-ordination with Bonneville downstream to generate benefits.

Response:

FBC is not an expert on the Columbia River Treaty (CRT) and plays no role in its negotiation or administration. FBC storage is on Kootenay Lake which is not a CRT reservoir. Therefore, FBC is not entitled to any of the benefits of the CRT nor does FBC have any obligation to support the CRT with water releases from Kootenay Lake. The local residents of Kootenay Lake do receive flood control benefits as a result of the CRT.

16.4 Please discuss any other historical circumstances that FBCU anticipate could assist in making a claim that power supply from BC Hydro should not be subject to continuous uncertainty from a planning perspective.

Response:

A historical circumstance that assists in FBC making a claim that power supply from BC Hydro should not be subject to continuous uncertainty from a planning perspective relates to the Canal Plant Agreement (CPA). The CPA limited FBC's opportunities to expand generation on the Kootenay River since BC Hydro built the Kootenay Canal Plant. As a result, FBC began buying power from BC Hydro and those purchases over time became embodied in the original 1993 BC Hydro PPA.

[15] Currently, FBC's ability to import intermittent power is limited to 100 MW under the FBC Scheduling Agreement with BC Hydro. If FBC is unable to negotiate increases to this limit with BC Hydro, it may be necessary to terminate the Scheduling Agreement, but that can only be done by terminating the BC Hydro PPA as well as it is linked to the PPA.

16.5 Please discuss whether or not FBCU have any ongoing discussions with the province and or BC Hydro in regard to BC Hydro & provincial policy in regard to the PPA with BC Hydro and, if so, elaborate on the productiveness of such discussions in generating certainty about renewal, perhaps with variability of the terms, conditions and pricing without removing certainty of the availability of the capacity and energy products.

Response:

Please refer to the responses to CEC IR1 14.5 and 16.2.

17. Reference: Exhibit B1-8-1, Appendix B, pages 41 and 49

> FBC assesses that, compared to the 2013 Proceeding, the operating risk facing the facilities in the FBC service area is increasing. Specifically:
>
> - Section 9.1 discusses how infrastructure integrity risk remains largely unchanged from 2013.
> - Section 9.2 discusses how unexpected events such as recent extreme weather-related events in the province, including record wildfire activity, flooding and mudslides, are expected to continue to occur and become more widespread.
> - Section 9.3 discusses how two of the risks (project resistance and cybersecurity) are newly identified operating risk categories since the 2013 Proceeding, and have become significant considerations for FBC.
>
> environmental activism threaten safe and reliable energy delivery to customers. Environmental concerns and general public resistance also represent a risk to FBC's ongoing annual vegetation management programs, which are very important in maintaining safe and reliable service.
>
> The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, environmental management for sensitive species and their habitat, and conducting environmental impact assessments and remediation. FBC is experiencing increasingly strict environmental and safety laws, regulations and enforcement policies since 2013.

17.1 Please confirm that when FBC complies with environmental regulation changes in its service area, that it is in fact reducing its business risk from public interest concerns and is in fact being positioned as a credible partner in protecting the public interest values of the community.

Response:

This would be accurate, other things being equal and assuming FBC is always able to comply with all environmental obligations. However, with the above-noted trend to impose more restrictions and limitations on activities that may impact the environment, FBC faces an increased risk that it will not be able to comply, whether due to strict prohibitions, lack of resources, or inability to meet compliance deadlines.

17.2 Please confirm that there are many other public interest values and indigenous community values to which FBC & FBCU is paying greater attention than in the past and that FBC & FBCU pride themselves in doing as a significant business in all of the communities it serves.

Response:

Confirmed.

17.3 Please confirm that FBC and FBCU are not in these comments advocating for less strict environmental and safety laws, or the lowering of public interest values that FBC and FBCU have been instrumental in adopting, and in many cases exceeding letter of the law standards.

Response:

FBC and FEI are not advocating for less strict environmental and safety laws in the evidence quoted in the question, but they do disagree with project resistance and environmental activism that threatens safe and reliable energy delivery to customers. FBC and FEI will continue to meet or exceed legal requirements relating to safety and the environment.

18. Reference: Exhibit B1-8-1, Appendix B, page 51; Exhibit B1-8-1, Appendix D-7.1, Historic Financial Information

> **10.1 *INCREASED RISK RELATED TO UNCERTAINTY AND LAG IN REGULATORY APPROVAL***
>
> FBC is subject to a number of regulatory regimes, with BCUC regulation being notable. As a regulated public utility, FBC can only construct significant utility assets with a CPCN approval. It can only charge rates that have been approved by the BCUC. The BCUC sets the allowed return on equity and capital structure of the utility, and assesses depreciation rates that permit recovery of invested capital. The BCUC, as a statutory entity, acts pursuant to its power under the *UCA* but, within that framework, has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight 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 FBC with an opportunity to earn its fair return on and of invested capital, or that necessary investments are not approved.

FortisBC Inc
Historic Regulatory Financial Information
($000)

		2016	2017	2018	2019	2020
		Actual	Actual	Actual	Actual	Actual
28	Achieved Pre-Earnings Sharing ROE	9.52%	9.41%	9.32%	9.15%	9.46%
29	Achieved Post-Earnings Sharing ROE	9.38%	9.31%	9.29%	9.18%	9.30%
30	Allowed ROE	9.15%	9.15%	9.15%	9.15%	9.15%
31						
32	Actual Pre-Earnings Sharing Return on Capital	6.78%	6.72%	6.76%	6.65%	6.68%
33	Actual Post-Earnings Sharing Return on Capital	6.72%	6.68%	6.75%	6.66%	6.62%
34	Approved Return on Capital	6.69%	6.79%	6.69%	6.71%	6.55%

18.1 Please confirm that contrary to the text that 'FBC is not provided an opportunity to earn a fair return on and of its invested capital' FBC has over the last number of years earned at or in excess of its allowed return on equity.

Response:

As can be seen from the preamble above, FBC has not stated that it has not been "provided an opportunity to earn a fair return on and of its invested capital"; rather, FBC's statement reads: "regulatory oversight 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 FBC with an opportunity to earn its fair return on and of invested capital, or that necessary investment are not approved". [Emphasis added]

In the 2016 cost of capital decision, the BCUC confirmed that risk analysis is prospective in nature and non-occurrence in the past is not an indication that the risk does not exist:

> AMPC/BCOAPO's position is for a risk to remain a risk, it must at some point occur. The Panel is not persuaded that this interpretation of risk is reasonable or reflective of the prospective nature of risk. In the Panel's view, a risk does not disappear because it has not occurred over a period of time and non-occurrence of a risk in the past does not necessarily alter the probability of occurrence in the future.

The Panel does not agree with CEC's assertion that equity investors are concerned primarily with immediate risk and current ROE performance as they can alter their investment when rewards fail to match the immediate risk. While investors certainly consider a risk which has recently occurred, they must be equally concerned about the future prospects of an investment. Further, while it is true investors may sell a particular investment; it would be imprudent of an investor to fail to consider the future prospects of an investment and any potential future risks which may occur.

18.2 Please provide any evidence FBC has that it has not been able to recover its capital through the regulatory process, other than capital which has not been prudently invested, if any.

Response:

Please refer to the response to CEC IR1 18.1 which clarifies that FBC's statement in the preamble is not suggesting FBC is not able to recover its capital through the regulatory process. In recognition that approvals of capital investment are the purview of the BCUC, FBC is referring to the fact that regulatory oversight gives rise to the risk that necessary investments are not approved, thereby foreclosing on FBC's opportunity to earn its fair return.

However, FBC notes that although not frequent, there have been instances where FBC was denied recovery of certain capital costs and therefore the associated allowed return, showing that this risk is real and indeed has materialized in the past. For example, in 2013 the BCUC conducted a prudency review of FBC's Kettle Valley Distribution Source Project and pursuant to Order G-47-13, approximately $115.7 thousand of expenditures incurred were denied recovery related to the underground feeder and additional land space for future site expansion.

18.3 Please update the above table for 2021 and provide historical information from 2000 through to 2015.

Response:

Please see below for historical information for FBC from 2011 through to 2020. Please note that historical information related to the return on capital back to 2000 (20 years) is not readily available, so is not provided here; however, FBC is able to provide the requested historical information to 2011 (10 years) and believes this provides a reasonable and relevant range of information between FBC's approved and actual returns. For further reference, FBC has also

provided historical approved and actual ROEs from 2002 through to 2010 as part of the response to ICG IR1 9.6. Information for 2021 is not available until the Annual Report is filed on April 30, 2021.

FortisBC Inc
Historic Regulatory Financial Information
($000)

Line no.	Particulars	2011 Actual	2012 [1] Actual	2013 [1] Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual
1	Achieved Pre-Earnings Sharing ROE	11.33%	10.52%	10.21%	9.29%	9.35%	9.52%	9.41%	9.32%	9.15%	9.46%
2	Achieved Post Earnings Sharing ROE	10.67%	-	-	9.22%	9.26%	9.38%	9.31%	9.29%	9.18%	9.30%
3	Allowed ROE	9.90%	9.90%	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%
4											
5	Actual Pre-Earnings Sharing Return on Capital	8.47%	8.01%	7.59%	7.06%	6.88%	6.78%	6.72%	6.76%	6.65%	6.68%
6	Actual Post-Earnings Sharing Return on Capital	7.99%	-	-	7.03%	6.84%	6.72%	6.68%	6.75%	6.66%	6.62%
7	Approved Return on Capital	7.67%	7.57%	7.18%	7.20%	6.83%	6.69%	6.79%	6.69%	6.71%	6.55%
8											
9	Notes:										
10	[1] Achieved Post Earnings Sharing ROE and Return on Capital not applicable as no Earnings Sharing Mechanism was approved in 2012 or 2013.										

18.4 Please confirm that regulatory oversight and openness and transparency are each a part of the regulatory compact that enable FBC and the FBCU to earn stable and certain returns on their equity capital investment, and therefore are not a source of risk but are indeed a source of certainty and stability.

Response:

Rate regulation, other things equal, does tend to reduce risk (particularly short-term risk) relative to the unregulated market. However, from the perspective of an investor considering investing in utilities, regulatory oversight and uncertainty caused by regulatory discretion in approving or denying a utility's applications represents a significant source of risk. For instance, as explained in FortisBC's evidence, together, the regulatory framework, and the ability to recover costs and earn returns (which are also dependent on regulatory oversight) have a 50 percent weighting in Moody's rating methodology, highlighting the importance of this risk. The sources of regulatory risk are also discussed in the academic literature[16].

18.5 Please confirm that FBC and FBCU also have the ability at any time to raise a complaint with the Commission that they have not earned a fair return on their equity investment of capital and/or that they have not been allowed to recover the costs of invested capital from the utility customers.

[16] For instance refer to the paper by Bastian Schwark titled "Influence of regulatory uncertainty on capacity investments", retrieved from: http://infoscience.epfl.ch/record/153004/files/15d_schwark_paper.pdf.

Response:

Retroactive complaints of this nature would not be permissible. However, FortisBC can file an application to increase rates. In practice, every rate increase sought by FortisBC is ultimately attributable to the belief of the utility that the current rates are insufficient to allow recovery of prudently incurred costs and achieve the allowed return.

18.6 Please provide the evidence that FBC and/or FBCU have filed a complaint or asked the Commission to reconsider its delivery of a return on equity that meets the fair return standard because FBC and/or the FBCU have not had a legitimate opportunity to earn its fair return on its invested equity capital.

Response:

Ordinarily, FortisBC would not file a complaint for re-setting the allowed ROE and capital structure. Rather, FortisBC may file a new application with reasoning as why a review is necessary including why the existing cost of capital does not meet the Fair Return Standard.

FEI's 2005 and 2009 applications for the review of its cost of capital are two examples. In both of these proceedings, FEI applied for a review of the allowed ROE and capital structure stating that the existing allowed ROE and capital structure did not meet the Fair Return Standard. For instance, in the 2009 proceeding, FEI provided the following reason, among others, to request a review:

> Third, the Terasen Utilities submit that the Commission is compelled to revisit the ROE formula based on its obligations under the *Utilities Commission Act*. In particular those parts of sections 59 and 60 which require that the Commission establish rates that are not unjust or unreasonable while providing investors in the public utilities regulated by the Commission an opportunity to earn a fair return on their capital …
>
> The Commission must adhere to the Fair Return Standard which has been established by Canadian and US courts and was reaffirmed by the NEB in the recent TQM Decision …
>
> The evidence presented in this Application demonstrates that this obligation is no longer being met by the current BCUC ROE formula.

The question of whether FortisBC has "a legitimate opportunity to earn its fair return on its invested equity capital" pertains to rate setting (revenue requirements applications), not the determination of the allowed ROE. That is, every time the FortisBC files for a rate increase it is because the

1 utility believes the current rates are insufficient to allow it to recover its prudently incurred costs
2 and achieve its allowed return.

3

19. Reference: Exhibit A11, BCUC IR39, Page 46-48

On page 52 of the Continental Economics Inc. report, Dr. Lesser notes that:

> FERC, for example, currently requires the use of a one-stage DCF model applied to the dividend paying firms of the S&P 500. FERC also excludes dividend-paying firms with negative earnings growth rate forecasts and forecasts greater than 20%. [emphasis added]
>
> ... FERC has justified the use of a one-stage DCF model applied to the dividend-paying firms of the S&P 500 to estimate the market return and MRP 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.
>
> FERC's rationale is based on a misconception. Using the expected returns for the S&P 500 or the TSX represent a proxy for the entire market. Although the composition of the S&P 500 and S&P/TSX change over time as firms are added and dropped, that conclusion cannot apply to the market as a whole. In other words, a firm does not vanish from the "market" simply because it is no longer included in a broad market index... 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.

19.1 Please confirm that the S&P 500 and the S&P/TSX have had substantial changes in the weighting of the types of companies that dominate these indexes over the years, and please describe the changes and provide quantitative evidence with respect to the changes.

Response:

Concentric provides the following response:

The composition of market indices changes periodically as new companies are added and old companies are removed. The question asks for changes in weighting over time but does not define a specific period. Mr. Coyne does not have specific information on the changes in weighting of the types of companies that dominate these indexes over time; however, in recent years the information technology sector has become a larger part of the S&P 500. Investors are able to purchase shares in an index fund that tracks the S&P 500 (or a similar index), and when they do, they expect to receive the return of all the companies in that index, not a subset of those companies.

FERC addressed the issue of changes in the composition of the S&P 500 Index in Opinion No. 531-B as follows:

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high

market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable. [Para 113]

19.2 Please confirm that the S&P 500 and the S&P/TSX contain a number of companies that are profiting and increasing their market capitalization as a consequence of successfully implementing new market-disrupting technologies and concepts causing dramatic transitions in their markets, and frequently those companies that have not innovated or adapted decline and may be dropped out of these indexes altogether or fail completely and disappear from the investment markets altogether.

Response:

Concentric provides the following response:

Mr. Coyne agrees that certain companies in the S&P 500 and S&P/TSX Index have developed market-disrupting technologies and are earning profits on those innovations. Utilities such as FEI are also being asked to develop market-disrupting technologies as part of the Energy Transition, but the profits they are allowed to earn on those innovations are constrained by regulation, unlike firms that are not subject to regulation.

Canadian Market DCF Calculation as of December 31, 2021

	[1]	[2]	[3]	[4]	[13]	[14]
	Dividend Yield	Dividend Yield x (1 + 0.5Dg)	Expected Growth Rate (g)	Secondary Market Investor Required Return	Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX	3.16%	3.28%	8.40%	11.68%	2.58%	9.10%

19.3 Please confirm that inclusion of an expected growth rate in any estimates does not deal with taxation impacts on estimated return, whereas the dividends are taxed annually.

Response:

Concentric provides the following response:

Dividends are taxed annually, while capital appreciation is taxable once the shares are sold. The estimated return is an after tax return, but individual investors may experience different after-tax returns depending on their tax status. The revenue requirement for regulated utilities is grossed up for the effect of income taxes.

19.4 Please confirm that investors in the FTS stock in addition to the taxed returns of annual incomes are rewarded with growth in the value of the FTS stock.

Response:

Concentric provides the following response:

Confirmed. Investors in FTS stock receive quarterly dividend payments, plus any capital appreciation that occurred in the share price between the purchase date and the sale date.

19.5 Please discuss how the estimating for a fair return standard incorporates the after-tax return perspective in the comparable data to ensure it is not overestimating required returns to be fair.

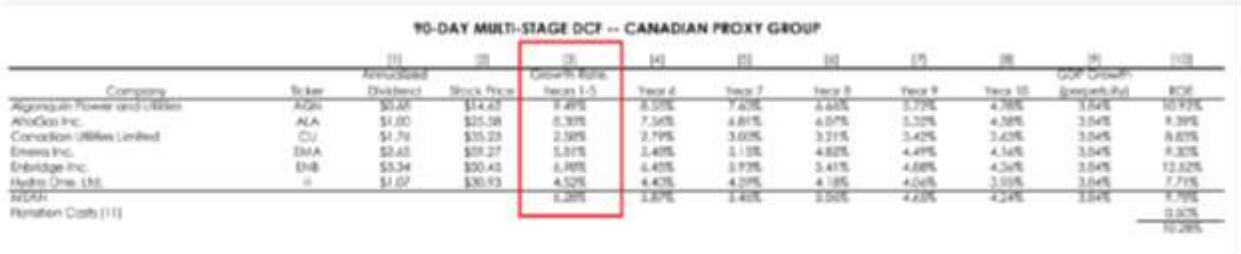
Response:

Concentric provides the following response:

Please refer to the response to CEC IR1 19.3.

The models used to estimate returns produce an after-tax return, which is grossed up for tax purposes at the utility level, which provides a fair basis for determining both after-tax and pre-tax returns.

20. Reference: Exhibit A11, BCUC IR42, Page 53; Exhibit B1-8-1 Appendix C, Exhibit JMC-FEI-5, Page 2



90-DAY MULTI-STAGE DCF -- CANADIAN PROXY GROUP

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 (years 11+)	[10] ROE
Algonquin Power and Utilities	AQN	$0.81	$14.43	9.49%	8.55%	7.60%	6.66%	5.71%	4.76%	3.84%	10.93%
AltaGas Inc.	ALA	$1.00	$25.38	6.30%	7.16%	6.81%	6.07%	5.32%	4.58%	3.84%	9.39%
Canadian Utilities Limited	CU	$1.76	$35.23	2.58%	2.79%	3.00%	3.21%	3.42%	3.63%	3.84%	8.65%
Emera Inc.	EMA	$2.63	$59.27	3.01%	3.40%	3.19%	4.82%	4.49%	4.16%	3.84%	9.30%
Enbridge Inc.	ENB	$3.34	$50.43	6.99%	6.40%	3.93%	3.41%	4.68%	4.26%	3.84%	12.32%
Hydro One Ltd.	H	$1.07	$30.93	4.52%	4.42%	4.29%	4.18%	4.04%	3.91%	3.84%	7.71%
MEAN				5.48%	5.80%	5.40%	5.06%	4.23%	4.24%	3.84%	9.79%
Flotation Costs [11]											0.30%
											10.08%

20.1 Please confirm that Enbridge Inc. stock and growth rate has substantial exposure to oil pipelines and that the risk premiums required for these risks are a confounding attribute of the inclusion of Enbridge in a Canadian Proxy Group.

Response:

Concentric provides the following response:

Enbridge Inc. does have substantial exposure to oil and gas pipelines, which are regulated by either by CER or FERC, but do have a different risk profile than a regulated gas distribution company. However, Enbridge Inc. is one of only three Canadian proxy group companies that is either primarily a gas company or a combination gas/electric utility. Enbridge Inc. derives about 16-17% of its net income from the gas distribution business. Again, this is why Mr. Coyne believes the U.S. gas proxy group is more comparable to FEI than the Canadian proxy group.

21. Reference: Exhibit A11, BCUC IR45, Page 57

On page 3 of Exhibit B1-8, FBCU states "the single biggest increase in risk relates to political/Energy Transition risk" in support of its request for the increase in ROE and equity thickness for FEI.

On page 78 of Appendix C, Mr. Coyne states:

> Additionally, restrictions on gas use in buildings have advanced at the state or local level in at least six U.S. states that collectively represent approximately one quarter of gas use in the U.S. These restrictions threaten new customer growth because they generally apply to new buildings, but in some cases, such as Washington and New York, state policymakers have also proposed plans that would phase out gas use in existing buildings. In juxtaposition to these developments, at least 19 other states have passed laws prohibiting gas bans at the local level. These prohibitions on gas bans are in stark contrast to the restrictive policies being implemented in BC and certain U.S. states at the forefront of the energy transition.

On page 19 of Appendix A, FEI states, "Climate action goals and legislation are moving forward at a rapid pace at all levels of government."

On page 112 of Appendix C, Mr. Coyne states, "all of Canada's gas utilities are operating in a state of adaptation to the Energy Transition."

21.1 Please discuss this transition risk in terms of whether or not there are credible options for managing and mitigating the risk allowed and enabled by the regulator as well as future technology options to manage and mitigate the risk, which may be expected to be allowed by the regulator.

Response:

Concentric provides the following response:

Please refer to the response to BCUC IR1 46.3. In addition to increasing the common equity ratio, other options for managing and mitigating risk due to the Energy Transition include accelerated depreciation rates and reducing the economic planning horizon. Future technology options may mitigate these risks, but cannot eliminate them as companies, such as FEI, must both recover existing investments and deploy newly developed technologies that must be approved by the regulator. It is this transition, with uncertainty, that creates the risk.

21.2 Please discuss this transition risk in terms of whether or not there is existing practice developed and implemented by the utility and approved by the regulator and recognized in provincial legislation, which demonstrates a solid realistic progress in meeting the challenges of the energy transition.

Response:

FEI has a solid, realistic plan to meet the challenges of the Energy Transition as it understands them today. However, there is currently no legislative framework in BC that deals with the role of the gas system and the challenges of the Energy Transition it faces in a solid, realistic manner. As explained in FEI's business risk evidence, the CleanBC Roadmap to 2030 identifies key priorities in regard to decarbonizing FEI's customer emissions in the buildings and communities, transportation, and industry sectors; however, its measures rely heavily on the electrification of energy end uses to reduce GHG emissions and do not provide comprehensive support for the role of the gas system.

While the role of the gas system has garnered some support and recognition from the Province in the form of support for the expansion of Renewable Gas supply, and while FEI is pursuing actions to reduce emissions as part of its 30BY30 target, there is no legislation recognized by the Province or approval by the regulator that outlines the overall role of FEI in the energy transition.

Although there are specific pieces of legislation like the GGRR and the DSM regulation that allow FEI to make progress in reducing GHG emissions, they are not incorporated into an overall framework that would address the energy transition risk to FEI.

Please also refer to the responses to BCUC IR1 4.4.1, 4.4.1.1 and CEC IR1 9.2 where FEI describes the kinds of actions that are required from the government and the BCUC for FEI to be able to credibly advance its Energy Transition mitigation related initiatives.

21.3 Please confirm that the primary risk for which concern should be the largest would be the failure to have solutions, to have proven implementations of the solutions, and to have a solid case for the preservation of the renewable natural gas system as a valuable diversity of supply to deal with the energy transition and comment of the solid progress FBCU has been making to manage the energy transition challenges.

Response:

FortisBC agrees that being stagnant and not having a plan to address the challenges associated with the Energy Transition also involves significant risk. As explained in the response to CEC IR1 2.5, FEI has put forward initiatives to proactively address anticipated risks; however, currently investors have doubts about the scalability and permanency of these solutions and perceive significant risk to these solutions.

Please refer to the responses to BCUC IR1 8.1.1 and 14.4.

22. Reference: Exhibit B1-8-1, Appendix C, page 91

> However, we note that this is a "downside-only" area for FEI. In other words, while regulatory changes (e.g., the acceleration of depreciation rates) may improve FEI's prospects of recovering its investment, there remains a chance that investors are not able to earn a full "return of" their invested capital. There is no reasonable scenario where investors face less risk due to stranded assets than before the advent of the Energy Transition. Further, all else equal, accelerating

22.1 Please confirm that a reasonable scenario for investors facing less risk due to stranded assets during the advent of the energy transition would be if a gaseous supply of renewable energy as a diverse and lower cost competition to electricity emerges as a long-term viable solution.

Response:

Concentric provides the following response:

As discussed on pages 85-87 of Mr. Coyne's report, renewable natural gas and hydrogen gas are among the alternative fuel sources that gas distribution utilities such as FEI may consider to meet the carbon emission targets of federal and provincial governments. However, investors and credit rating agencies have expressed concerns with RNG and hydrogen as alternatives and the cost of such alternatives is not currently competitive with electricity, especially in provinces such as BC where there is low-cost hydro.

22.2 Please provide any quantitative analysis that this potential long-term option cannot and will not emerge as viable, thereby realizing the stranded asset risk.

Response:

Concentric provides the following response:

There are so many unknowns that the only reasonable approach is scenario analysis.

Mr. Coyne has not conducted such quantitative analysis, but he refers to the work completed by CER that considers alternative energy futures. Please refer to the response to RCIA IR1 3.2 for an overview of this work.

22.3 Please confirm why, if there is no reasonable scenario where there will be less risk of stranded assets, continued investment in the gas system assets should continue.

Response:

Concentric provides the following response:

Continued investment in the gas distribution system is necessary in order to maintain the safety and reliability of the existing infrastructure and meet the energy needs of customers through the transition. The Energy Transition will occur gradually, and natural gas will remain an important fuel source for the foreseeable future.

Please refer to the response to BCUC IR1 9.4 where FEI's discusses the reasons for its major capital projects spending.

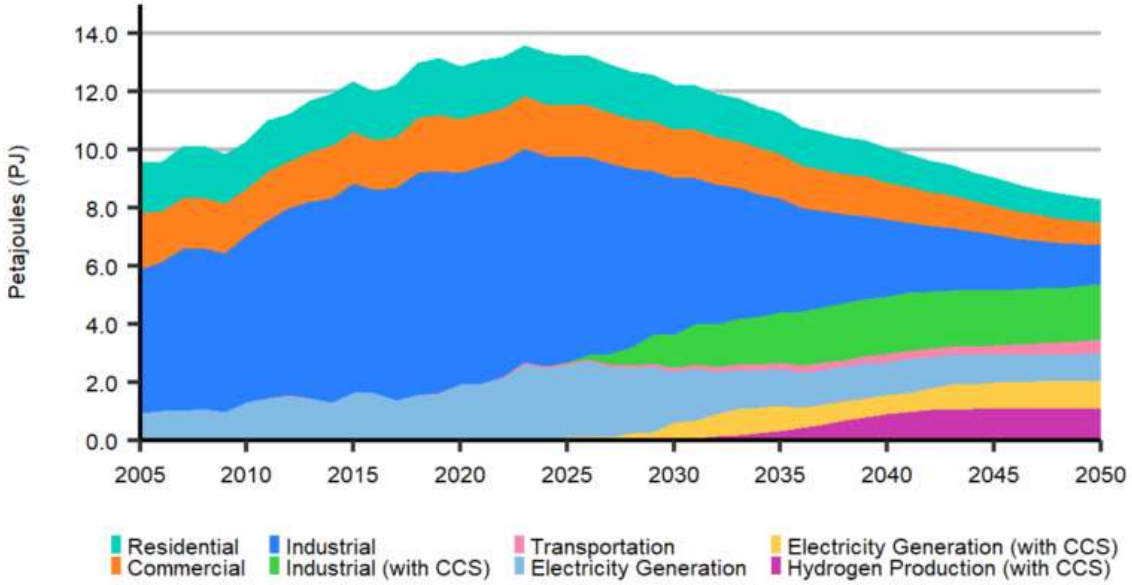
22.4 Please identify the scenarios considered when determining that there is no future scenario with less risk for stranded assets.

Response:

Concentric provides the following response:

Mr. Coyne did not consider specific scenarios with regard to the risk of stranded assets for FEI. He notes, however, the most recent analysis of the CER in its scenarios for Canada's Energy Future released February, 2022. In this report and appendices, the CER projects primary energy demand, by province, and nationally. For natural gas, the projected demand nationally is depicted below:

Figure ES.14:
Natural Gas Demand by Sector, Evolving Policies Scenario



In BC, as noted in response to RCIA IR1 3.2, natural gas demand declines by more than 20% by 2050. The CER characterizes this scenario as: "The Evolving Policies Scenario was introduced as the new primary scenario of the Canada's Energy Future series in EF2020." [17] The CER also considered a "Current Policies", and a "Towards Net Zero" scenario. The CER further characterized the scenarios: "The Evolving and Current Policies scenarios do not explicitly model climate goals or targets. Given its static policy framework, the Current Policies Scenario is extremely unlikely to lead to the significant GHG reductions needed to meet Canada's Paris commitments. In the Evolving Policies Scenario, significant GHG emission reductions will be realized, but ambitious goals such as net-zero by 2050 are unlikely to be met."

Mr. Coyne interprets these results as an indication that even the Evolving Policies scenario will be insufficient to meet Canada's net zero by 2050 commitment which became law under the Canadian Net Zero Emissions Accountability Act in June 2021. The projections for natural gas demand in BC and more broadly in North America point to the potential for stranded assets as one of the risks investors face in gas utilities due to the Energy Transition.

22.5 Please confirm that FBCU and FEI are proposing to both the BC Government and to the BCUC that they expect to develop a viable long-term path to meeting GHG

[17] Canada's Energy Future 2021, CER, pp. 19, 24.

reduction targets by 2050, and they have demonstrated success in delivering GHG reductions to these targets already.

Response:

With respect to CEC IR1 22.5, FortisBC assumes that CEC was referring to FBC and FEI in the information request as opposed to FBCU and FEI.

Confirmed.

22.5.1 Please confirm that while the future is not guaranteed, the FBCU has no reasons or evidence to suggest that it will fail in its energy transition endeavors to find the appropriate provincial balance between renewable gaseous energy supply and electrical transmission energy supply in the quest to deliver GHG reductions to meet provincial targets.

Response:

While FEI and FBC intend to meet provincial GHG targets, their success depends on a number of factors beyond FEI and FBC's control. As such, FortisBC cannot confirm that there is no evidence to suggest FEI or FBC will fail.

Please also refer to the response to BCUC IR1 4.4.1 and 4.4.1.1.

23. Reference: Exhibit B1-8-1, Appendix C, page 91

Figure 50: Comparison of Deemed Equity Ratios

Operating Utility	Deemed Equity Ratio
FortisBC Energy Inc. (existing)	38.5%
FortisBC Energy Inc. (proposed)	45.0%
AltaGas Utilities, Inc.	39.0%
ATCO Gas	37.0%
Enbridge Gas	36.0%
Energir (formerly Gaz Metro)[198]	38.5%
Gazifere Inc.[199]	40.0%
Heritage Gas Limited	45.0%
Liberty Gas New Brunswick	45.0%
Pacific Northern Gas Ltd.[200]	46.5%
Pacific Northern Gas Ltd. (Fort St. John/Dawson Creek)	41.0%
Canadian Gas Average	**40.9%**
Canadian Gas Median	**40.0%**
US Gas LDC Average (2020/2021)[201]	**52.0%**
US Gas Proxy Group Average	**53.4%**

23.1 Please provide the recent annual revenues for each of the utilities in the Figure 50 list, so that they may be considered based upon the size of the utility.

Response:

Concentric provides the following response:

Please see the table below, which provides 2019 information on the number of customers, annual throughput, and annual revenues for the companies listed in Figure 50.

Company	2019 Customers	2019 Annual Throughput (000 GJs)	2019 Annual Revenues C$ (millions)
AltaGas Utilities	80,700	20,686	$117.2
ATCO Gas	1,232,400	270,505	$824.1
Enbridge Gas	3,755,000	516,999	$5,084
Energir (formerly Gaz Metro)	207,000	238,700	$1,561.9
Gazifere	43,500	7,000	$228.4
Heritage Gas Ltd	7,700	10,100	$121.3
Liberty Utilities Gas New Brunswick	12,000	5,575	$49.3
Pacific Northern Gas Ltd	42,000	10,159	$264.2
FEI	1,041,000	227,000	$1,331.0

23.2 In the response to BCUC question 51.1, please supply the revenues for each of the US utilities included in US group data.

Response:

Concentric provides the following response:

Please refer to CONFIDENTIAL Attachment 23.2 for the requested revenues for each company in 2020 as reported on S&P Capital IQ.

Attachment 23.2 is being filed on a confidential basis with the BCUC, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Concentric advises that the information is proprietary and only available to subscribers who, under the terms of the license, are not to reproduce, redistribute or store in a public retrieval system without prior written consent, which has not been obtained. Therefore, Attachment 23.2 is being provided confidentially under separate cover to the BCUC only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

23.3 Please confirm that as the Generic Cost of Capital proceeding moves forward, the ROE's and Equity to Debt thickness will be determined for smaller regulated utilities and that these usually have higher ROEs than the benchmark and potentially thicker Equity to Debt thickness.

Response:

According to BCUC Order G-156-21, the cost of capital for utilities other than FEI, FBC and BC Hydro will be determined in the second stage of this GCOC proceeding. FortisBC also confirms that currently, these smaller utilities have a higher ROE and equity ratio than FEI. FortisBC however cannot speculate whether or not the BCUC determines that these premiums should continue to hold going forward.

24. Reference: Exhibit A11, BCUC IR53, Page 63

On page 121 of Appendix C, Mr. Coyne states

> S&P credit metrics for FEI for 2020 were significantly weaker than the S&P credit metrics of the companies in the U.S. Gas proxy group.
>
> [...]
>
> This shows that FEI's financial risk profile is weaker on every measure than the U.S. Gas proxy group companies. This stands to reason since the U.S. Gas proxy group has an average S&P credit rating of A, which is one notch higher than FEI's long-term issuer rating from Moody's of A3 (equivalent to A- from S&P).
>
> Comparisons to the Canadian proxy group also reveal weaker but more comparable credit metrics.
>
> [...]
>
> The average S&P credit rating of the Canadian proxy group is BBB+, or one notch lower than FEI's long-term issuer rating from Moody's of A3 (equivalent to A- from S&P).

24.1 Please provide the rating metrics and any quantitative supporting credit metrics for each of the companies Mr. Coyne has compared FEI to, as well as the Credit metrics for FEI and please confirm whether or not FEI has its own credit rating or whether the FTS stock credit rating are what is being referenced.

Response:

Concentric provides the following response:

Credit metrics for each company in the Canadian and U.S. proxy groups are provided in Exhibit JMC-FEI-10. FEI is not rated by S&P. FEI has a Moody's long-term issuer rating of A3, as indicated in Mr. Coyne's report.

25. Reference: Exhibit B1-8-1, Appendix C, page 151 and 133

Figure 65: Comparison of Authorized Equity Returns

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%

Figure 57: Comparison of Canadian Investor-Owned Electric Utilities

Company	2020 Retail Customers[207]	2020 Annual Sales (000 GWh)[208]	2020 Annual Revenues C$ (millions)[209]
FortisBC Inc.	143,714	3,291	$412
ATCO Electric	260,552	12,012	$1,218
FortisAlberta	572,000	16,092	$596
Hydro One Networks	1,449,629	28,379	$7,290
Nova Scotia Power	529,000	10,028	$1,494
Newfoundland Power	270,000	5,729	$717
Maritime Electric	84,000	1,293	$219

25.1 Please provide, for each of the US utilities in the comparison in Figure 65, the same data as for the Canadian companies provided in Figure 57, including their annual revenues.

Response:

Concentric provides the following response:

Please refer to CONFIDENTIAL Attachment 25.1.

Attachment 25.1 is being filed on a confidential basis with the BCUC, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Concentric advises that the information is proprietary and only available to subscribers who, under the terms of the license, are not to reproduce, redistribute or store in a public retrieval system without prior written consent, which has not been obtained. Therefore, Attachment 25.1 is being provided confidentially under separate cover to the BCUC only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

26. Reference: Exhibit B1-8 page 9

> Section 59(5) of the UCA provides that a rate is "unjust" or "unreasonable" if it 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.

26.1 Please describe what may be considered as 'more' than a fair and reasonable charge, or 'less' than a fair and reasonable charge.

Response:

Section 59(5)(a) refers to the BCUC's obligation to approve rates which are fair and reasonable having in mind the purpose for which the service is used, the quantities purchased and such other matters as the BCUC considers justify the approval of rates which differ for different users. Prudently incurred costs are recoverable in rates. Charging less than a fair and reasonable charge would include rates based on something less than what is required to prudently deliver the quality and quantity of service that the BCUC deems to be appropriate. Conversely, more than a fair and reasonable charge would include rates based on something more than is required to prudently deliver the quality and quantity of service that the BCUC deems to be appropriate.

Section 59(5)(a) is a distinct requirement from section 5(5)(b). In coming to a conclusion of a fair return for the utility, the BCUC does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the BCUC has a duty to approve rates that will provide a reasonable opportunity for the utility to earn a fair return on invested capital.

26.2 Please confirm that once the Commission has established a Fair return, it is considered to be the Fair return unless or until it is changed by the Commission.

Response:

Confirmed. A fair return established by the BCUC remains a fair return unless or until it is changed by the BCUC or overturned on appeal.

26.3 Please confirm that the regulatory compact followed by the Commission and the FBCU does not involve dealing with a fair and reasonable return on the appraised value of the FBCU property but rather on the equity component of the investment in the costs of the assets in the utility rate base.

Response:

FEI and FBC's return on equity is set based on the equity component of the investment in rate base, which is determined with reference to the book value (not market value) of assets.

27. Reference: Exhibit B1-8, page 10

> Similarly, in FEI's 2016 Cost of Capital Decision (2016 Decision), the BCUC reiterated the principles articulated in the 2006, 2009 and 2013 Cost of Capital Decisions and confirmed that it has a duty to provide a reasonable opportunity to the utility to earn a Fair Return on and of invested capital:
>
> > Consistent with previous decisions and the "regulatory compact" the Panel confirms that it has a duty to approve rates that meet this standard, and to provide a reasonable opportunity for the utility to earn a Fair Return on invested capital. The Panel also concurs with the finding in the 2013 GCOC Decision that in assessing the Fair Return Standard, the utility must be assessed on the basis of the stand-alone principle. That is, it must be assessed as if FEI is a stand-alone entity, raising capital on the merits of its own economic, business and financial characteristics[21]. No party challenged the application of this principle[22].

27.1 Please confirm that the Utility is not guaranteed to earn a 'Fair Return' but is provided a reasonable opportunity to earn a fair return on its invested capital.

Response:

The allowed return determined by the BCUC must reflect the Fair Return Standard. FortisBC confirms that, once that allowed return is determined, the BCUC must set rates that provide a *reasonable opportunity* to earn that fair allowed return on its invested capital.

27.2 Please discuss the meaning of 'having a reasonable opportunity' to earn a Fair Return on invested capital. What conditions can be considered as a 'reasonable opportunity'?

Response:

There is a statutory obligation on the BCUC, set out in sections 60 and 59(5) of the *Utilities Commission Act*, to approve rates that afford the utility an opportunity to earn a fair return. Judicial authorities have referred to this obligation as "absolute".[18]

The conceptual underpinning is that the utility's cost of capital is a legitimate cost of providing safe and reliable utility service. The BCUC is determining in this proceeding the amount of that cost (the "allowed return"), for which provision will be made in rates set by the BCUC. Establishing the allowed return for the utility at a level that fails to reflect its true cost of capital as determined with reference to the three standards of capital attraction, financial integrity, and comparable

[18] *British Columbia Electric Railway Co. v. Public Utilities Commission*, [1960] S.C.R. 837 at 848 and 856-857; *TransCanada PipeLines Ltd*. v *National Energy Board*, 2004 FCA 149, paras. 35-36 and 43.

returns would be no more valid than a determination to disallow rate recovery for a prudently incurred capital or operating cost.

27.3 What conditions could be present under which the Utility is regulated in a fair manner, but does not earn its expected Fair Return?

Response:

When setting a rate under section 60 of the *Utilities Commission Act*, the BCUC must have due regard for, among other things, whether the rate provides the utility an opportunity to earn a fair return. This standard does not mean, however, that a utility is guaranteed its allowed return on equity. In any particular year, the actual return on equity earned may be below or above the allowed return on equity. The rates may be set based on a forecast revenue requirement for the year, which includes a provision for the allowed return on equity. The utility's actual performance during the fiscal year will determine how close the actual return on equity will be to the allowed return on equity.

The inability to earn the expected return may also happen due to the ratemaking approach and associated regulatory lag. For instance, under incentive regulation, the utility's revenue requirement may be set for a number of years. In any given year, the utility may spend more than its approved revenue requirement in which case it will not be able to recover the variance between actual and allowed costs (even if the costs were prudently incurred). This can potentially result in a utility earning less than its allowed return.

28. Reference: Exhibit B1-8, page 10

> This BCUC's articulation of the Fair Return Standard is consistent with prior court decisions, including the concurring reasons of Locke J, in *British Columbia Electric Railway*, in which Locke J, stated in part:
>
> > The Commission is directed by s.16(1)(a) [of the old legislation] to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute.[23]
>
> The application of the Fair Return Standard ensures that utilities are in a position to:
>
> - meet their customers' service needs at a reasonable cost;
> - attract investment capital at reasonable cost under all market conditions;
> - earn a fair and reasonable return on previously invested capital;
> - support the energy and environmental policy objectives of the BC government to the extent appropriate under the UCA;
> - pursue investments in efficiency; and
> - be financially sustainable in the face of ongoing and changing business risks.

28.1 Please confirm that when the decision says "ensures" that it does not mean that these issues are guaranteed as a matter of the fair standard return but have reasonable prospects of being delivered by the company and its management.

Response:

It is unclear what decision is being referred to in the question, but as discussed in the response to CEC IR1 27.3, setting rates with regard for the Fair Return Standard does not mean that a utility is guaranteed to earn its allowed return on equity. The application of the Fair Return Standard to determine the allowed return, and the corresponding step by the BCUC to ensure that rates reflect the allowed return on a forecast basis, allows the utility and its management the opportunity to address the listed items, but does not guarantee that they will occur.

28.2 Please explain whether or not utilities have an obligation to deliver any and all of the six bullet pointed items above, if they have been provided with a 'fair return'.

Response:

The obligations of public utilities are primarily as set out in the *Utilities Commission Act*, including the obligation to provide service to the public that is adequate, safe, efficient, just and reasonable without undue discrimination. Over the long run, unless a utility is allowed to earn its cost of

1 capital, further investment will be discouraged and it will be unable to maintain its operations
2 including with respect to the bulleted items in the preamble.

29. Reference: Exhibit B1-8, page 12 and https://www.investopedia.com/ask/answers/041415/variance-good-or-bad-stock-investors.asp

> **4.1 FortisBC's Approach to Assessing Business Risk Aligns With the BCUC's Definition of Risk**
>
> In the 2013 GCOC Stage 1 Decision (2013 Decision) and the 2016 Decision, the BCUC defined risk as the probability that the future cash flows will not be realized or will be variable resulting in a failure to meet investors' expectations[25]. The BCUC's 2013 Decision also reaffirmed its previous statement in the 2009 Cost of Capital Decision (2009 Decision) that "*the assessment of the risks has a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes.*"[26]

Variance is neither good nor bad for investors in and of itself. However, high variance in a stock is associated with higher risk, along with a higher return. Low variance is associated with lower risk and a lower return. High-variance stocks tend to be good for aggressive investors who are less risk-averse, while low-variance stocks tend to be good for conservative investors who have less risk tolerance.

29.1 Please confirm or otherwise explain that the statement in the GCOC Stage 1 Decision (2013) would be considered to be on average, and does not imply that investors are guaranteed to earn their expected results.

Response:

FortisBC confirms that investors are not guaranteed to earn their expected returns.

29.2 Please confirm the above Investopedia statement regarding variability is a reasonable perspective.

Response:

Concentric provides the following response:

Mr. Coyne does not dispute this Investopedia statement regarding variability of stock prices. As discussed in Mr. Coyne's report, Beta is the common measure of risk in the CAPM. Beta measures the relative change in the share price of the subject company compared to the broad market over a specified time period, such as five years. As noted in Mr. Coyne's report, Betas for regulated gas and electric utilities have increased substantially since January 2020.

29.3 Please discuss the variability of the FTS stock price as a proxy for (FEI and FBC on a standalone basis, but confirm it will need adjustment to ensure it reflects the standalone principle).

Response:

Concentric provides the following response:

Please refer to Attachment 29.3 for an analysis of the variability in FTS's stock price for each year from 2017 through 2021. As shown in the summary table below, the variability in the high and low stock price for FTS each year has ranged from 18.5% in 2018 to 39.4% in 2020.

	Low Price	High Price	% Variability
2021	49.00	61.16	24.8%
2020	42.20	58.83	39.4%
2019	44.27	56.78	28.3%
2018	39.69	47.05	18.5%
2017	40.87	48.59	18.9%

Fortis Inc. is not included in Mr. Coyne's Canadian or North American proxy groups because FTS is the parent company of FEI and FBC, and would not typically be considered a proxy for the subsidiary companies for purposes of regulatory cost of capital analysis.

In particular, Fortis Inc. is an imperfect proxy for estimating the cost of equity for either FEI or FBC because neither operating company accounts for a significant portion of the earnings or asset base of the parent company. Please also refer to the response to CEC IR1 7.2.

30. Reference: Exhibit B1-8, page 12

> Business risk can be categorized in different forms. For the sake of consistency and continuity of risk assessment, in this proceeding FEI and FBC have both adopted similar business risk categories to each other, which are consistent with the 2016 Proceeding. The only new risk category relates to the Indigenous rights and engagement that due to its increased significance and impact has now been promoted to its own risk category. These categories conform to the BCUC's definition of risk, since each one of these risk categories (and each one of the factors within each category) can potentially limit FEI's and FBC's ability to realize its current and future earnings and/or cash flows.[27]

30.1 Please confirm that the BCUC is not obligated to be consistent with the 2016 Proceeding or any other prior proceeding, and can incorporate other factors into its Decision-making as it deems fit.

Response:

Section 75 of the UCA provides "The commission must make its decision on the merits and justice of the case, and is not bound to follow its own decisions."

FORTISBC ENERGY INC.

31. Reference: Exhibit B1, page 18 and Appendix A page 17 and page 18

- *Economic Conditions*: The current Canadian economic environment continues to be dominated by uncertainty. FBC's assessment of major economic indicators indicates that BC is recovering from the pandemic lows. Nevertheless, 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. In addition, compared to other larger utilities, FBC's smaller size and dependence on highly cyclical industrial load in one or two sectors contribute to FBC's higher economic related risk.

Table A3-1: Economic Indicators for Four Jurisdictions in Canada (2015 to 2023)[14]

	2015	2016	2017	2018	2019	2020	2021F	2022F	2023F
British Columbia									
Real GDP (% change)	2.3	2.9	3.7	2.8	2.5	-3.8	5.2	4.0	2.5
Unemployment (%)	6.2	6.1	5.2	4.7	4.7	8.9	6.5	4.7	4.5
Housing starts (1000 of units)	31.4	41.8	43.7	40.9	44.9	37.9	47.6	36.1	34.8
Alberta									
Real GDP (% change)	-3.5	-3.6	4.3	1.9	0.0	-8.2	5.3	5.0	4.0
Unemployment (%)	6.1	8.2	7.9	6.7	7.0	11.4	8.7	7.1	6.4
Housing starts (1000 of units)	37.3	24.5	29.5	26.1	27.3	24	31.4	30.9	28.8
Ontario									
Real GDP (% change)	2.7	2.2	2.8	2.9	2.1	-5.0	3.9	4.9	3.2
Unemployment (%)	6.8	6.6	6.0	5.7	5.6	9.6	8.0	5.8	5.3
Housing starts (1000 of units)	70.2	75.0	79.1	78.7	69.0	80.8	99.5	83.6	83.3
Quebec									
Real GDP (% change)	1.0	1.6	2.9	3.0	2.7	-5.3	5.9	3.6	2.4
Unemployment (%)	7.6	7.2	6.1	5.5	5.1	8.9	6.1	4.6	5.0
Housing starts (1000 of units)	37.9	38.9	46.5	46.9	48.0	53.4	67.8	54.8	49.4

Based on the Conference Board of Canada (CBOC) long-term forecast, from 2026 to 2040, economic growth is forecast to average 1.5 per cent, slightly less than the growth expected for Canada's economy as a whole[15]. Demographic issues are expected to further lead to lower housing starts over the long term as the aging population lowers the demand for new homes. Housing starts are forecast to decline from around 38,000 in 2020 to 18,000 in 2040. These long-term forecasts for both GDP and housing starts are lower than what was forecast in the CBOC's 2015 long-term forecast indicating that in the CBOC's view, BC's long-tem outlook is slightly worse than what was assumed in 2015. As for investments, according to the CBOC, once the Coastal GasLink project is completed in 2024–2025, there will likely be a limited number of large-scale projects. In addition, new emission targets under BC's climate plan may work to limit further expansion in a sector that could otherwise be a growth driver, the province's LNG sector.

In conclusion, FEI's assessment of BC's major economic indicators indicates that BC is recovering from the pandemic lows and that, with exception of the unemployment number, the 2022 forecast numbers for housing starts and GDP growth are higher than the 2015 levels. Nevertheless, 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.

31.1 Please provide the BC GDP by Industry - NAICS Aggregations, for the years from the most recent data available back to 2006 to demonstrate the FBCU assertion that forestry has been volatile or risky.

Response:

Please find below data from 2006-2020 in dollars and percentage form, which includes information for the NAICS aggregations for *Forestry and Logging, Wood Product Manufacturing* as well as *Paper Manufacturing*.[19]

[19] Statistics Canada. Table 36-10-0402-01 Gross domestic product (GDP) at basic prices, by industry, provinces and territories (x 1,000,000).

BC GDP by Industry - NAICS Aggregations, 2006-2020 (Millions of Dollars)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forestry and logging	**2,188**	**2,055**	**1,813**	**1,248**	**1,533**	**1,814**	**1,860**	**2,011**	**1,977**	**1,970**	**1,807**	**1,841**	**1,977**	**1,578**	**1,695**
Wood product manufacturing	**3,128**	**2,965**	**2,508**	**2,043**	**2,281**	**2,408**	**2,579**	**2,780**	**2,810**	**2,842**	**2,991**	**2,892**	**2,744**	**2,433**	**2,226**
Paper manufacturing	**1,739**	**1,709**	**1,521**	**1,170**	**1,385**	**1,428**	**1,299**	**1,208**	**1,398**	**1,457**	**1,359**	**1,248**	**1,215**	**1,046**	**911**

BC GDP by Industry - NAICS Aggregations, 2006-2020 (Percentage of Annual Change)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
All Industries	3%	1%	-3%	3%	3%	3%	2%	4%	2%	3%	4%	4%	3%	-3%	3%
Forestry and logging	-6%	-12%	-31%	23%	18%	3%	8%	-2%	0%	-8%	2%	7%	-20%	7%	-6%
Wood product manufacturing	-5%	-15%	-19%	12%	6%	7%	8%	1%	1%	5%	-3%	-5%	-11%	-8%	-5%
Paper manufacturing	-2%	-11%	-23%	18%	3%	-9%	-7%	16%	4%	-7%	-8%	-3%	-14%	-13%	-2%

As can be seen, the three forestry related sectors exhibit more volatile annual changes than the “All Industries” category, indicating the cyclical nature of forestry related industries.

31.2 Please confirm that all businesses are exposed to economic risk.

Response:

Confirmed that all businesses are exposed to varying types and degrees of economic risk.

31.3 FEI evaluates most of its Business Risk with respect to the 2015 levels. Please confirm that the business risk for many if not most other companies has also changed since 2015 and that FEI must make a case related to a current comparable investment.

Response:

As explained in the FortisBC evidence, business risk can be analyzed in various fashions. For instance, one can analyze the business risk by comparing the direction and pace of change in risk factors for the same company over time. In its evidence, FEI's and FBC's Business Risk Appendices (Appendix A and Appendix B) assess each Company's business risk from this perspective. Another important approach, particularly in the context of cost of capital applications, is to analyze a company's risk relative to other firms. Concentric's expert testimony in this proceeding includes this aspect of business risk analysis. Similar to what is stated in the question, Concentric's relative risk comparison to other firms relies on current comparable investments and not on the 2013 or 2015 risk levels.

As discussed in the response to BCOAPO IR1 2.1, the BCUC's past decisions have relied on both of these approaches to inform its cost of capital determinations.

31.4 Please confirm that an assessment of business risk with respect to an ability to attract investment should evaluate the business risk relative to other businesses in the current timeframe, not necessarily with respect to previous times.

Response:

Please refer to the response to CEC IR1 31.3.

31.5 Please provide a fulsome discussion for how FEI's economic risk has changed relative to other businesses.

Response:

As explained in FEI's business risk appendix, the main economic risk event in today's economic environment relates to the COVID-19 pandemic and its impact on supply chain issues as well as record high inflation. FEI believes that inflation risk has a similar impact on utilities generally. For a more fulsome discussion about the economic risk please refer to the responses to BCUC IR1 13.1.1 and 13.2.

32. Reference: Exhibit B1-8, page 18 and Exhibit B1-8-1 Appendix A page 21

- *Political Risk*: The government push for electrification of the BC economy 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, and government's ability to subsidize BC Hydro customers is not a path open to FBC. Overall, however, FBC assesses that its political risk is lower than what was assessed in the 2013 Proceeding.

While there is broadening consensus among policymakers on the need to achieve net-zero emissions over the long-term, there is considerable uncertainty on what role the gas system will play in achieving these goals and how policymakers will utilize the gas system for a net-zero transition.

While gas infrastructure is a promising tool to reach decarbonization goals, there is a lack of awareness and acceptance of the role it could play. This creates a higher risk for FEI relative to the political risk environment at the time of the 2016 Proceeding. This higher level of risk must be managed with continued investment in research, analysis, and development of low-carbon solutions within a net-zero context, and engagement with policymakers at all levels of government and key stakeholders who inform climate change-related policy development.

32.1 Please confirm that the BC government has also made a push on a number of fronts to be supportive of the natural gas business including renewable natural gas options.

32.1.1 Would FEI expect that such activities can moderate the political risk? Please explain why or why not.

Response:

The BC government has been supportive of expanding the supply of renewable gases. However, significant barriers and risks remain with respect to policy and to date the support has been outweighed by a number of detrimental government policies. For instance, government policy has not addressed the barriers associated with expanding the use of renewable gas in BC. Moreover, the CleanBC Roadmap and related policies introduce a number of policies that will serve to impede the use of renewable gases in the future, including:

- Introduction of 100 percent efficiency standards that restrict the use of conventional gas appliances by 2030[20];
- Phasing out of incentives for conventional gas appliances and equipment;
- Introduction of incentives and funding to promote fuel switching from fossil fuels to electric heat pumps; and

[20] Renewable gas is currently burned in conventional gas appliances, which cannot achieve 100 percent efficiency. Gas-fired heat pumps, which can exceed 100 percent efficiency, are not yet commercialized and widely adopted in the marketplace.

- Increased PST on conventional gas appliances.[21]

The lack of clear direction regarding the role of the gas system in BC's energy future elevates the risk of lower throughput and higher prices, which can negatively influence FEI's ability to recover costs over the long-term. As explained in Concentric's evidence, while RNG and hydrogen may offer a potential pathway for FEI through the Energy Transition, investors perceive significant risk to that pathway because of its operational, political, technical, and financial challenges.

32.2 Please confirm that FEI can and generally does recover such expenses from ratepayers.

Response:

FEI is unclear what expenses the CEC is referring to.

FEI's statements in the preamble above do not relate to the ability to recover costs in the short-term. Rather, FEI's statement focuses on the demand and price implications of government's policies to decarbonize the economy on FEI's business, which can negatively influence FEI's ability to recover costs over the long-term.

32.3 Please confirm that FEI can and does recover such expenses from its ratepayers.

Response:

Please refer to the response to CEC IR1 32.2.

[21] Introduced as part of the 2022/2023 Provincial Budget.

33. Reference: Exhibit B1-8-1 Appendix A, page 22

> **4.2.1 Federal Government**
>
> Both the federal Liberal and NDP parties committed to greater effort to meet and exceed the Paris targets, including a pledge to reach net-zero by 2050. In the fall of 2020, the Liberal government announced a new climate plan to exceed its 2030 targets, signaling carbon tax increases, deep energy and climate policy reform, and significant public investment into energy transition efforts. Of significance, within the plan is a proposed carbon tax escalation of $15 per tonne per year after 2022, reaching $170 per tonne by 2030. Section 6.3.2 outlines the impact this will have on FEI's price and competitive position. Most recently, at the COP26 conference in November 2021, the federal government announced a cap on oil and gas sector emissions[21] to reach net-zero by 2050.
>
> There are many policies and agendas that affect the timing and magnitude of risk that FEI faces. Additionally, the lack of clarity from federal and provincial policymakers on the role of the gas system in decarbonization has increased risk and uncertainty for FEI. While the solutions that FEI offers to align with a low-carbon future would assist with the federal government's goals, a lack of program support, stringent policies and favouring one solution set over others put FEI's system and ratepayers at risk. FEI's risk due to federal government policies is significantly higher than in the 2016 Proceeding. Some specific policies are discussed below.
>
> ***4.2.1.1 Pan-Canadian Framework***
>
> The Pan-Canadian Framework on Clean Growth and Climate Change[22] (PCF) was Canada's first national climate plan and was released in December 2016 (after the 2016 Proceeding), marking a shift towards increased federal involvement in climate policy. The PCF has four main pillars: pricing carbon pollution, complementary measures to reduce emissions, climate change adaptation and actions to accelerate innovation. Most notably, the PCF contained measures to significantly reduce emissions in the buildings sector by making new buildings net-zero, retrofitting existing buildings, fuel switching, improving energy efficiency for appliances and equipment and supporting building codes and energy efficient housing. The PCF set an aspirational goal in 2017 that by 2035 all space heating technologies sold have a performance of greater than 100 percent efficiency. This would effectively ensure that only electric or gas heat pumps would be available for use by this time. The PCF signalled further electrification measures for the buildings sector and fuel switching from natural gas.

33.1 When FEI is evaluated for business risk against other companies, please provide an overview of the types of companies which it may be assessed against.

Response:

Concentric provides the following response:

Mr. Coyne compared the business risk of FEI against other gas distribution utilities in Canada and the U.S. Those companies are most similar in risk and are appropriately included in a proxy group for FEI, although each company has its own unique business and financial risks.

33.1.1 Would these include other energy companies that are also exposed to new federal and provincial regulations? Please explain.

Response:

Concentric provides the following response:

All North American gas distributors are exposed to some degree to new federal, provincial and state policies that impact business risk. Some distributors are more exposed to Energy Transition risk (such as in BC) and others are more insulated from that risk through prohibitions on natural gas bans.

33.1.2 Would these include other companies facing market disrupting technology changes creating transitions similar to the energy transition FEI is dealing with? Please explain.

Response:

Concentric provides the following response:

Yes, all North American gas distributors are facing market disrupting technology changes. One example is the electric heat pump, which is rapidly penetrating the home heating and air conditioning market and capturing market share. But this type of competition from new technology is not as far reaching as the Energy Transition. As stated elsewhere in these responses, the Energy Transition is a market disrupting phenomenon for gas distributors, which are not normally exposed to this type of risk. The Energy Transition limits the future growth prospects of companies like FEI and requires them to fundamentally re-examine their business model.

33.2 Please identify which other types of companies FEI would expect would also experience risk as a result of federal climate plans.

Response:

FEI would expect that all companies using gas and electricity would experience heightened risk if the preferred pathway to decarbonization was electrification-focused. As discussed in the Pathways to 2050 report, such a pathway would see higher energy rates and lower energy system resiliency which would impact companies across a wide spectrum.

For example, FEI would expect companies competing in energy-intensive, trade-exposed industries to be at higher risk. This includes companies that:

- Have relatively high energy costs as a share of gross output;
- Compete in international markets with divergent climate policy stringency; and
- Extract, process, distribute, or retail carbon-based energy commodities.

Other examples of impacted companies include:

- Companies that are involved in the production, transmission and distribution of gaseous energy; and
- Companies that manufacture, maintain and sell products used to burn gaseous energy.

34. Reference: Exhibit B1-8, page 15 and Exhibit B1-8-1 Appendix A page 28 and page 29

- *Energy Prices*: The risk relating to energy prices is higher than what it was in the 2016 Proceeding. 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. Furthermore, 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 2016 Proceeding. In terms of competitiveness, 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 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 further contributes to FEI's higher price competitiveness risk. The upfront and installation costs of natural gas-fired equipment have increased relative to the cost data available in 2015 for that same equipment. 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.

4.2.2.2 Electrification

The Roadmap, based on the measures outlined above, is supportive of greater electrification, placing pressure on FEI to retain customers and grow its business by attracting new customers. This, in turn, can force FEI to become less cost competitive over time. The section below highlights how the Buildings Electrification Roadmap and BC Hydro Electrification Plan further aim to electrify many aspects of BC's economy, including loads currently served by FEI.

4.2.2.2.2 BC HYDRO ELECTRIFICATION PLAN

The Electrification Plan[33] initiated by BC Hydro was launched in September 2021 as part of its Revenue Requirements Application. The Electrification Plan proposes new programs and incentives to switch from fossil fuels to electricity in homes and buildings, transportation and industry. BC Hydro plans to spend $360 million on electrification initiatives over the next five years, of which $190 million will be used to encourage customers to switch from natural gas and diesel to electricity.

In the buildings sector, BC Hydro identified expanding residential air source heat pumps and switching from natural gas furnaces as a key strategy. While BC Hydro acknowledges that there are still barriers for building owners switching to electric heat pumps, mainly affordability, a new incentive allows customers to receive up to $11 thousand per household if they switch from natural gas to an electric heat pump. In the Industrial sector, BC Hydro also identified displacing fossil fuels and attracting new load from traditional resource industries and manufacturing.

The Electrification Plan states that electricity rates will go down for customers for the years that the Electrification Plan is in its "testing phase" between 2021-2026[34]. The Electrification Plan does not discuss the long-term costs or potential impacts of relying on electrification-only measures past 2026 and rate impacts of electrifying substantial natural gas loads and what that means for British Columbians.

34.1 Please provide FEI's views as to how electrification can be expected to impact the electricity rates beyond the 'testing phase'.

Response:

FEI has not attempted to quantify the rate impact of the BC Hydro Electrification Plan beyond the 2021-2026 testing phase, but agrees that over the short term and based on the evidence provided by BC Hydro to date, the expected electrification will be manageable with existing resources and infrastructure without a material impact on rates. Beyond 2026, it becomes more likely that a sole focus on electrification will place upward pressure on rates. The view of FEI is that the province has a number of options to reach its long-term climate goals. One pathway is electrification, which relies on the widespread use of electricity. The other, and the one that FEI views as the preferable approach, is a diversified pathway, which utilizes different sources of clean energy, including electricity, as well as renewable gases which take advantage of its gas delivery infrastructure. The costs for both electric and natural gas ratepayers are higher in the electrification pathway as compared to the diversified pathway as BC Hydro's existing capacity surplus is exhausted and additional resources are required and there is less load on the FEI system to cover fixed costs.

34.2 Please explain whether or not FEI's risk should be assessed only over the 3-5 years term of the Cost of Capital hearings, or whether the risk should be assessed on a long-term basis of say 10 or 20 years or more.

Response:

Please refer to the response to BCOAPO IR1 19.1.

35. Reference: Exhibit B1-8-1, Appendix A page 33-34, and page 35

Table A4-1: Sample List of Local Governments and their Low Carbon Energy System (LCES) Targets

Local Government	Building Energy Requirement	Types of Buildings Impacted	Effective Date
District of West Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Single family, townhouse and other Part 9[47] residential buildings	February 2021
	Either Step 5 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 9 Detached secondary suites	
	Either Step 4 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3[48] residential Multi-family and apartment buildings.	
District of North Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 9 Single family home, coach house, smaller townhouse.	July 2021
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Residential Larger multi-family and apartment projects	

2

Local Government	Building Energy Requirement	Types of Buildings Impacted	Effective Date
	Either Step 3 or Step 2 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Commercial, Office and Retail buildings	
City of North Vancouver	Either Step 5 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Newly constructed Part 9 residential buildings	July 2021
City of Burnaby	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$)	Rezoning applications for Part 3 residential and commercial buildings	July 2019
City of Surrey	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$)	Part 3 Residential new construction	April 2019
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$)	Part 3 Residential new construction	2023-2024
City of Richmond	Either Step 3 or Step 2 with a Low Carbon Energy System (6 $kgCO_2e/m^2$) or ≤ 1.2 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	December 2020
	Either Step 3 or Step 2 with a Low Carbon Energy System	Part 3 Residential Buildings more than 6 stories or non combustible construction	January 2021
	Either Step 4 or Step 3 with a Low Carbon Energy System (3 $kgCO_2e/m^2$) or ≤ 0.6 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	January 2022
	Either Step 5 or Step 4 with a Low Carbon Energy System (3 $kgCO_2e/m^2$) or ≤ 0.6 tCO_2e / year	Part 9 Single family dwellings and duplexes, townhomes and apartments	January 2025

Municipality	Low Carbon Energy Systems Definition
Surrey	A highly efficient, professionally operated and maintained mechanical system that supplies a building's space, heating, cooling and domestic hot water heating demand primarily from renewable energy sources, at a carbon intensity that is low enough so that when applied to modelled building energy use, the development satisfies the City's defined GHG limits. The City's District Energy System for Surrey City Centre is considered an LCES.
Richmond	A building's space heating, cooling, and domestic hot water heating mechanical system that is supplied with energy through either a connection to city-owned district energy system or, an on-site energy supply equipment designated to meet a minimum of 70% of building annual heating, cooling, and domestic hot water energy demand from a renewable energy source.
Port Moody	A professionally designed and maintained, highly efficient mechanical system that supplies a building's space heating, cooling, and domestic hot water heating demand primarily from renewable energy sources, and meets defined greenhouse gas intensity (GHGI) limits of 6 $kgCO_2e/m^2$/year and a coefficient of performance (COP) greater than 2.

In summary, increasing autonomy of local governments to set emissions reduction targets will limit energy choices for customers and create unequal access to conventional and Renewable Gas service in FEI's service territory. For instance, a new building in a municipality with a GHGi target will not have access to FEI's conventional natural gas service, while another new building across the street in a different municipality without a GHGi target may be able to use conventional natural gas. Similarly, the efficiency requirements in Port Moody preclude the use of gas equipment entirely whereas neighboring municipalities have not adopted this stringent standard.

3

4 35.1 Please elaborate on why there will be unequal access to RNG.

Response:

To clarify, municipal regulations are creating unequal access to FEI's gas system for customers to use either conventional or Renewable Natural Gas.

Since the 2016 Proceeding, the climate and energy policies at the local government level have evolved with a variety of measures implemented at a much faster pace. A growing number of municipalities are using various approaches to reach their ambitious GHG reduction targets. These include the adoption of stringent BC energy Step Code (Step Code) levels for new buildings and/or requiring the builders to meet or exceed certain GHGi targets per square metre of floor space, effective bans on the use of conventional natural gas equipment by requiring efficiency levels higher than 100 percent, requiring the connection to District Energy Systems (DES) and other measures such as financial and non-financial incentives for all electric options for space and water heating applications. Furthermore, an increasing number of local governments (such as the City of Surrey and District of Squamish- see response to CEC IR1 35.2) are enacting policies or incentives that favour the use of electricity over Renewable Gas to lower emissions in buildings, creating a significant impediment on the ability for a customer or builder/developer to access FEI's gas system.

35.2 Please discuss whether or not FEI's RNG program could be reasonably expected to meet or contribute to meeting all the municipalities' LCES targets if gas equipment is not precluded entirely and explicitly.

Response:

FEI's RG Program in its current format cannot meet the municipal requirement; as such, FEI is seeking approval for changes to the RG Program to meet local government GHG regulations for new construction. There remains uncertainty about any future government policy that may impact the RG Program. For example, in 2020 the City of Vancouver approved its Climate Emergency Action Plan which includes a Zero Emissions Buildings Retrofit Strategy for existing buildings offering a phased approach to reduce carbon pollution from the operation of existing buildings by 50 percent by 2030, up to 100 percent before 2050[22]. The approach being proposed by the COV is to reduce emissions at the building level where replacement heating and hot water systems must be zero emissions. While FEI has a solution to decarbonize its gas supply and achieve the CleanBC targets, which will meet the CoV's 2030 emission target goals, it is our understanding that this approach does not appear to be acceptable to the CoV.

[22] City of Vancouver Climate Action Plan – Appendix J – p. 1 of 79

35.3 Can FEI's RNG be a significant contributor to low carbon district energy systems? Please explain why or why not.

Response:

Yes. While individual business models within District Energy Systems (DES) may vary, they could use RNG as a cost effective system that would have an equally low or lower carbon footprint when compared to electricity. RNG contracts are typically for 20 years and consequently provide a long term energy solution for District Energy Systems. Further, from a technology and equipment perspective, since several District Energy Systems are currently using natural gas equipment to heat their communities, using RNG to reduce their emissions brings the benefit of not having to perform significant system re-design and capital expenditures resulting from changing energy sources.

However, from a regulatory or policy perspective, the implementation of RNG into a low carbon district energy system is not as straightforward. For the City of Vancouver, a Neighbourhood Renewable Energy System (NRES) will be recognized if the NRES is City-owned, or once the renewable energy supply is secured by legally binding agreement or equivalent regulatory approach[23]. Renewable Gas' current regulatory framework will not provide adequate permanence that directly associates a customer with a permanent supply of renewable energy supply.

In addition, if DES requirements evolve similar to Port Moody's to meet a coefficient of performance (COP) greater than 2, RNG's low carbon footprint would be irrelevant. Of importance would be the equipment. Since gas equipment (regardless of traditional gas or RNG) does not currently meet a COP of greater than 2, RNG would effectively be eliminated.

35.4 Please explain what FEI would find as less risky; individual municipalities setting energy and environmental bylaws on a GHG reduction outcome basis or setting bylaws on a prescriptive 'how to do it' basis.

Response:

Both approaches carry risk and can have a similar impact on FEI and therefore one is not clearly more or less risky than the other.

[23] https://vancouver.ca/files/cov/zero-emissions-building-plan.pdf

An example of a performance approach is specifying that equipment efficiency achieve a COP of at least 2[24] which is practically achievable only by electric equipment as gas furnaces, boilers and water heating efficiency levels are less than the 100 percent. In this case, equipment efficiencies are being used as a surrogate to support electrification.

An example of a prescriptive approach is specifying no connection to the gas grid. For example, the City of Surrey approved a Zero carbon Incentive to be applied to new buildings built at the Darts Hill neighborhood. The qualification criteria is

> To be eligible for the incentive, buildings must fulfill the following criteria, in addition to any BC Energy Step Code and City of Surrey energy and sustainability provisions already in effect or otherwise required:
>
> ***Zero-carbon For All Buildings***: 100% of site and building operational energy needs are met with non-polluting energy, including heating, hot water, and cooking, as well as other energy needs such as pool heating. *The buildings are not connected to a fossil fuel supply grid*.[25]

35.5 How can FEI influence the provincial government to enable sensible decision making when they choose to enable a distributed approach to rule setting for industry and commercial enterprises?

Response:

FEI provides service to 135 communities across BC including 58 First Nations communities, and our natural gas and electricity infrastructure crosses more than 150 traditional territories. While FEI recognizes that each community is unique and can have energy needs that are reflective of their individual community, energy infrastructure is planned and implemented at a regional and provincial level. Thus, distributed approaches to energy policy and decision making can lead to a patchwork of regulation and challenges to the planning and operation of energy infrastructure serving broad areas.

However, FortisBC seeks to engage with communities to ensure that energy decisions taken at the community level consider broader goals of reliability, affordability, safety and sustainability across its infrastructure. FEI has recommended to the province that, as an alternative to distributed approaches to energy policy, broader and earlier stakeholder engagement should be conducted to incorporate the unique challenges faced by First Nations, local communities and

[24] Port Moody LCES definition – as per preamble to the question.
[25] Darts Hill NCP – p.183

1 businesses in its policy decision. Although the Province has not provided any plans for expanded
2 consultation, FEI will continue to advocate for this change.

3

36. Reference: Exhibit B1-8, pages 15 and 16

> - *Demand/Market:* Overall, since the 2016 Proceeding, FEI's demand/market risk has increased. Customers' energy choices are increasingly influenced by a desire to minimize negative environmental impacts. While Renewable Gas can be a relatively affordable option to achieve this goal, the electric options such as high-efficiency heat pumps are gaining faster and more widespread traction among customers and policy makers. FEI is already experiencing the effects of this shift in its net customer additions, particularly 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. Further, the gradual decline in the single-family dwelling segment, where FEI has higher capture rates, in favour of multi-family dwellings and the downward trend in the share of natural gas in space heating and water heating applications continue to impact FEI's risk profile. FEI's new residential customers continue to have lower use per customer (UPC) than average residential customers do. This is somewhat offset by load growth in the more volatile and economically sensitive transportation and industrial sectors.

36.1 Please confirm that FEI's customers continue to view natural gas favourably, as demonstrated in FEI's recent BERC rate methodology report.

Response:

The BERC Rate Methodology Report[26] described how the modifications to the BERC rate proposed in 2015 have successfully achieve their objectives. The report also tangentially demonstrated that customers view RG favourably.

FEI understands however that this question is referring to conventional natural gas. In this respect, many of FEI's customers positively view access to FEI's infrastructure and the attributes of a gaseous fuel. In Section 5.2 of FEI's Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, FEI noted that many customers enjoy the affordability, resilience, and comfort of service from FEI while at the same time supporting reduced GHG emissions and energy efficiency generally.

As noted on page 79 of Appendix A in FEI's evidence, "affordability and environment are the two main factors that influence existing customers' energy choices, whereas, the results for that same study in 2012 and 2013 indicated that perceived reliability and safety of the energy source were the primary influencers of customers' energy choices."

In this vein, a growing portion of FEI's customers are reducing emissions via electrification. The provincial government's 2020 Climate Change Accountability Report outlines year over year increases in electric heat pump sales, with increases of 47 percent and 52 percent respectively for 2018 and 2019.[27]

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[26] Biomethane Energy Recovery Charge (BERC) Rate Methodology, August 12, 2020.

[27] https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/2020_climate_change_accountability_report.pdf pp. 27.

36.2 Please place the BERC rate methodology report on the record in this proceeding.

Response:

Please refer to Attachment 36.2. FEI notes that the requested report was filed in August 2020 and much of the information in that report has been updated in FEI's Comprehensive Review and Application for approval of a Revised Renewable Gas Program, which was filed in December of 2021.

37. Reference: Exhibit B1-8, page 19

> - *Energy Supply*: Relative to 2015 levels, FEI's energy supply risk remains similar. Availability and accessibility of natural gas supply to FEI's service territory remains unchanged, as natural gas producers forecast production increases to meet growth in demand for gas-fired power generation and LNG. In terms of delivery risk, FEI continues to rely on a single system for a significant portion (currently 80 percent) of its gas requirements, and the material supply risk that this represents was highlighted in 2018 when Enbridge's T-South pipeline (or Westcoast T-South system) ruptured. The expansion of FEI's Renewable Gas supply adds new energy supply risk considerations since the 2016 Proceeding, such as the risks of lower than expected supply volume, competition from other purchasers, natural gas system readiness, and acceptance of non-local supply.

37.1 Please confirm that a key strategy of FEI's is to increase its proportion of Renewable Natural Gas (RNG) in its fuel supply.

Response:

Confirmed.

37.2 Please confirm that FEI expects to be able to secure enough RNG to meet its targets.

Response:

At this point in time FEI expects to be able to secure enough RNG to meet its targets. However, as the targets move out in time, the uncertainty increases. This is primarily for two reasons.

First, FEI is not sure of what those targets will be and they can change. For example, for some years FEI has been targeting that 15 percent of its supply would be low carbon by 2030. On October 25 2021, in its update on the CleanBC plan, the Province indicated that they planned to implement an emissions cap on the natural gas sector which would imply a need for a much higher amount than 15 percent of low carbon gas. This new target has not found its way into legislation yet and is only eight years away.

The second reason is that as times passes, FEI expects to see more competition for RNG which could manifest in higher prices and/or scarcity of supply. For that reason, FEI is diversifying its supply into other low carbon fuels such as hydrogen. While FEI is confident that it can incorporate hydrogen into its delivery systems, it is not currently something that is done outside industrial applications, so the work needed to make the system ready and the speed and extent of adoption by customers is less certain.

37.2.1 Please discuss whether or not the increase in RNG will serve to mitigate risk for fuel supply environmental quality.

Response:

FEI is not clear on what is meant by “fuel supply environmental quality”. Please refer to the response to CEC IR1 10.5 for discussion on an increase in RNG supply as a risk mitigation tactic.

38. Reference: Exhibit B1-8, page 16

> • *Operating*: FEI's overall operating risk has increased since the 2016 Proceeding. Operating risk factors continue to include infrastructure integrity and time dependent threats, and third party damages. Unexpected events also continue to contribute to FEI's operating risks. Since 2015, events such as the COVID-19 pandemic and the Enbridge T-South pipeline rupture, as well as more frequent extreme weather events, have highlighted the ever-changing nature of unexpected events facing FEI. 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. Furthermore, unlike in the 2016 Proceeding, FEI now identifies its operating risks as including negative sentiment towards companies within the fossil-fuel industry which increases the risk of protests and environmental activism against utility assets, challenges recruiting top talent to a carbon-based industry and poses difficulty and delays in obtaining capital project approvals or operating permits, and increases cybersecurity risk across many aspects of its operations. FEI is also facing municipal challenges to its right to construct and operate that were not previously experienced as frequently or at the level FEI experiences today. All of these factors working together increase FEI's overall operating risk.

38.1 Please confirm that FEI is undertaking multiple large infrastructure projects that are intended to reduce risk.

Response:

Large infrastructure projects have many drivers, including integrity and capacity that enable FEI to continue to serve its customers safely and reliably and to maintain its expected level of service (to customers, the public, regulators, etc.). As discussed in the response to BCUC IR1 19.1, FEI's current approved projects maintain operating risk at a stable level.

FEI has three proposed large infrastructure projects that could potentially reduce specific risk.

Large Infrastructure Project	Risk	Expected Capital Cost ($ millions)
Coastal Transmission System Transmission Integrity Management Capabilities (CTS TIMC)	Asset failure	138
Advanced Metering Infrastructure (AMI)	Extended service disruptions to customers	638
Tilbury LNG Storage Expansion (TLSE)	Extended service disruptions to customers	769

These projects are before the BCUC, not yet approved and have long implementation timelines.

38.1.1 Please itemize the projects related to risk reduction with their expected capital costs.

Response:

Please refer to the response to CEC IR1 38.1.

38.1.2 Please provide a quantitative assessment of the risk reductions with respect to these major project risk impacts over the next 5 to 10 years if the projects were not undertaken and relative to the last 5 or 10 years when the projects were not contemplated or in the process of being approved by the BCUC.

Response:

FEI is unable to quantitatively assess the risk reductions of the three major projects that could reduce specific operating risks. A qualitative assessment of risk change is provided in the table below.

Large Infrastructure Projects with resulting general (not site-specific) risk reductions	Description of Project Operating Risk Reduction	Qualitative assessment of risk change relative to last 5 or 10 years with projects	Qualitative assessment of risk change over the next 5 to 10 years if projects were not undertaken
Coastal Transmission System Transmission Integrity Management Capabilities (CTS TIMC)	This project primarily enables FEI to manage the threat of cracking to relevant transmission pipelines by providing crack detection in-line inspection capabilities. In-line inspection (ILI) data does not, in and of itself, provide a risk reduction. Rather, the data enables FEI to better understand the integrity condition of its system and undertake any necessary site-specific repairs. Site-specific failure risk may be reduced if the ILI tool runs (subsequent to the project) detect imperfections that meet the repair threshold, and	Operating risk remains stable. The proposed in-line inspection capabilities are to enable the continued safe operation of FEI's transmission pipelines, consistent with their safe operating history.	Cracking is a time-dependent threat to transmission pipelines, meaning that its potential to impact the pipeline increases over time. In the absence of the capabilities provided by the CTS TIMC project, the time-dependent cracking threats on transmission pipelines could grow, undetected, to failure. Operating risk would increase.

Large Infrastructure Projects with resulting general (not site-specific) risk reductions	Description of Project Operating Risk Reduction	Qualitative assessment of risk change relative to last 5 or 10 years with projects	Qualitative assessment of risk change over the next 5 to 10 years if projects were not undertaken
	such repairs are performed.		
Advanced Metering Infrastructure (AMI)	This project enables FEI to mitigate the risk of large extended service disruptions.	Operating risk can be improved. FEI would still be at risk if customer demand exceeds available supply.	Operating risk would remain relatively unchanged.
TLSE	This project primarily enables FEI to mitigate the risk of potential short term supply disruptions, including those that may originate from the T-South system.	Operating risk will be improved. If the TLSE Project was built with a storage tank size of 3 Bcf and 800 MMcf/day of regasification capacity, the additional resiliency benefits compared to FEI's resiliency capability today would include the ability to withstand a three-day no-flow event on T-South system for all but the coldest design day.	Operating risk would remain relatively unchanged.

38.1.3 Please explain whether or not the risk reduction infrastructure projects can be expected to reduce operating risk.

Response:

The large infrastructure projects proposed by FEI, if approved, could reduce specific operating risk as explained in the response to CEC IR1 38.1 and to the extent qualitatively assessed in the response to CEC IR1 38.1.2.

As stated in FortisBC's evidence, FEI's overall operating risk is increasing and is impacted by a wide-range of issues including:

- Infrastructure and time-dependent threats;
- Third-party damage;
- Negative sentiment towards the fossil-fuel industry;
- Municipal challenges;
- System resiliency risks, as illustrated by the Westcoast T-South pipeline rupture;

- Extreme weather events that are impacting FEI's operations; and
- Evolving cybersecurity risks that are impacting FEI's cybersecurity mitigation practices.

38.1.4 Please explain whether or not FEI has factored in the risk reduction infrastructure projects in its assessment of its operating risk, or any other risk factor.

13.1.3.1 If it has factored the projects in, please explain in what ways.

Response:

FEI has factored in its approved risk reduction infrastructure projects in its assessment of its operating risk.

FEI's approved infrastructure projects are not materially changing FEI's operating risk, as explained in the responses to CEC IR1 38.1 and BCUC IR1 19.1. The three large infrastructure projects that could reduce FEI's operating risk are currently under review by the BCUC, not approved at this time, and will have long implementation timelines.

As stated in the FortisBC Evidence, FEI's overall operating risk is increasing since the 2016 Proceeding due to wide-ranging issues of which one is infrastructure and time-dependent threats.

39. Reference: Exhibit B1-8, page 16 and Exhibit B1-8-1 Appendix A page 119

> - *Regulatory*: The degree to which FEI, 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 is what is referred to in this section as regulatory risk. FEI has assessed its overall regulatory risk as higher than what was assessed in FEI's 2016 Proceeding, with certain risk factors increasing and others being similar. The BCUC's jurisdiction is confined to what is conferred by the UCA, but within that framework the BCUC has significant discretion in the exercise of those powers. 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. The risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2016 Proceeding, with new challenges in both BCUC and other regulatory processes. There are increased requirements for stakeholder consultation, environmental reviews, Indigenous rights and title and municipal operating challenges.
>
> If the BCUC takes a restrictive interpretation of legislation, applies traditional rate-making principles in a way that impedes development, or emphasizes short-term affordability over resilience and decarbonization goals, this can hinder FEI's ability to implement important initiatives that align its operations with government policy and promote FEI's role in the low-carbon economy.
>
> Further, due to the uncertainty around the future role of natural gas in BC's energy infrastructure, FEI's capital intensive CPCN projects are also facing a higher level of regulatory uncertainty such that the BCUC may be hesitant to approve projects that add to the system capacity and lead to higher rates. This, in turn, will impact FEI's ability to adapt to a low carbon environment.

39.1 Please provide any evidence that FEI has that the BCUC can reasonably be expected to change its existing approach to ratemaking such that it impedes development or emphasize short term affordability over resilience and de-carbonization.

Response:

FEI clarifies that in order for the BCUC to support FEI's resiliency and decarbonization goals a change to the BCUC's existing approach may actually be needed and not that a change to the existing approach necessarily impedes development and implementation of FEI's initiatives.

As stated in FortisBC's evidence, an example could be the low-carbon gas alternatives such as Renewable Gas that have a higher cost basis than traditional natural gas, requiring approval of different cost recovery approaches. There is significant uncertainty as to how the BCUC should reconcile its traditional focus on encouraging utilities to "increase efficiency, reduce costs, and enhance performance," with a focus on encouraging utilities to undertake costly GHG reduction initiatives. As an example, the BC government has developed legislation (the GGRR) that enables utilities such as FEI to recover the costs of its initiatives that support GHG reduction efforts, and to recover them from all customers; in the absence of such legislation there is no explicit support

in the UCA for this approach. Further, FEI currently has an application before the BCUC that explores innovative rate design alternatives that have not been tested before the BCUC in the past.

39.1.1 Please confirm that the need to adopt decarbonization is not a regulatory risk, but is instead a political risk as discussed and accounted for earlier in FEI's submissions.

Response:

Please refer to the response to BCUC IR1 20.2.

39.1.2 Please confirm that accomplishing GHG reduction in line with the government targets is not a risk but rather is a substantive reduction of risk.

Response:

Not confirmed.

As stated in FortisBC's evidence, investors perceive a significant risk to the alternative fuel pathway and while FEI is taking steps to actively position itself in response to the Energy Transition, there is no reasonable scenario where investors face less risk than before.

Please refer to the response to the BCUC IR1 8.1.1.

39.2 Please provide an analysis of FEI's regulatory risk related to other companies with which it might be reasonably compared by an investor.

Response:

Concentric's evidence (Appendix C), already includes a comparative analysis of FEI's regulatory risk to other Canadian and U.S utilities. The following is a synopsis of this analysis.

Utility	Comparative risk analysis
Enbridge	Like BC, Ontario's utilities operate under PBR plans that have similar regulatory protection through ratemaking where deferral accounts, revenue stabilization mechanisms and capital trackers for major projects provide the opportunity for utilities to earn their allowed returns. According to UBS, the regulatory environment is less favorable for utilities in Ontario than in BC, while S&P ranks BC and Ontario as having similar regulatory environments.
ATCO Gas	In terms of the regulatory environment, the credit rating agencies indicate that the AUC has historically been known for transparent and predictable regulation. However, from an investor perspective, UBS ranks the AUC in Tier 4 as compared to Tier 1 for the BCUC. The AUC provides regulatory protection in the form of weather stabilization, load balancing, fair depreciation practices, and has established a number of deferral accounts to protect ATCO Gas from uncontrollable cost fluctuations. Further, both Alberta and BC have adopted PBR plans.
Energir	Like the case in other Canadian provinces, Energir is provided regulatory support through revenue stabilization, deferral accounts and capital trackers that provide the opportunity to earn its allowed return.
U.S utilities	Test year: FEI operates on a fully forecast test year. Slightly more than half (56 percent) of the operating utilities held by the U.S. Gas proxy group set rates based on a forecast or partially forecast test year. Purchased gas adjustment mechanism: Like FEI, the operating companies in U.S. Gas proxy group have little exposure to commodity price risk or supply risk due to the prevalence of fuel pass-through mechanisms. Revenue decoupling: FEI's operating revenues are fully decoupled from changes in volume. U.S. gas utilities are increasingly protected from market (or demand) risk, with 75 percent of the proxy group operating companies protected by either full or partial decoupling mechanisms. Cost recovery mechanisms: Regulatory lag is mitigated through the use of generic infrastructure riders (which provide cost recovery between rate cases for accelerated replacement of gas mains), capital trackers, and deferral accounts which are employed by the vast majority of the proxy group. FEI has protection against regulatory lag, including recovery of conservation program costs, infrastructure replacement, and other various deferral and variance accounts. Among the operating companies in the U.S. Gas proxy group, 50 percent have generic infrastructure riders, and 50 percent have a deferral account or other mechanism to recover costs associated with conservation program expenses. Environmental regulations: FEI is subject to some of the most aggressive carbon reduction targets in North America, including natural gas restrictions and electrification initiatives that would require customers to find alternative fuel sources by a date certain. Among the U.S. proxy group, 50 percent of the operating companies are located in states with carbon reduction targets, although most are not as aggressive as in BC, while 50 percent provide service in states that have passed legislation prohibiting bans on natural gas and prohibiting electrification initiatives.

1

2 For more details, please refer to pages 104 to 116 of Concentric's evidence (Appendix C).

39.3 Please confirm that system capacity expansion projects should be based on fully justified expected changes in system capacity needs and demand anticipated from customers.

Response:

Confirmed that system capacity expansion projects should be based on reasonable demand and capacity forecasts.

39.4 Please provide any evidence that FEI has that the Commission is or has been reluctant to approve fully justified expected changes in system capacity or in risk reduction projects.

Response:

FEI offers the following examples of the BCUC's recent desire to explore the future longevity of FEI's Coastal Transmission System (CTS) pipelines; however, it should be noted that the BCUC has yet to make final determinations in these proceedings.

In BCUC Panel IR1 for the TLSE Project, the Panel asked a number of questions regarding the future utilization of the Lower Mainland (i.e., CTS) pipelines. Some examples include:

1.1 Please provide a range of forecast scenarios for firm peak demand in the Lower Mainland (LML) in 2030 and 2050, which at a minimum outline a high, reference and low demand forecast.

1.2 Please discuss the expected resource mix (e.g. conventional natural gas, renewable natural gas, hydrogen etc.) that FEI anticipates would serve customers in the LML while meeting provincial greenhouse gas (GHG) targets in 2030 and 2050. Please also discuss the extent to which the resource mix may change in a higher or lower load scenario.

1.3 If not addressed above, please discuss the extent to which the proposed tank would be used and useful if FEI supplied no conventional natural gas by 2050.

Similarly, in BCUC Panel IR1 for the CTS TIMC Project, the Panel asked a number of IRs regarding the future transition to more renewable gas (including hydrogen) and the resulting impacts on the lifespan of the CTS pipelines. For example, BCUC Panel IR1 1.5 asked:

1.5 Please explain whether any of the pipelines modified in the CTS TIMC Project will no longer be used or useful following the blending of increasing concentrations of hydrogen into the CTS. Please explain why or why not.

In its responses to both sets of Panel IRs, FEI provided evidence that it is confident that the CTS pipelines will continue to be used and useful even in an increasingly decarbonized future, and that there is no need to adjust depreciation rates for either project's assets at this time. The BCUC subsequently issued a letter[28] requesting comments from both FEI and interveners stating that [footnotes omitted]:

> **The Panel remains concerned about the impact of future hydrogen blending on the value of the project assets in the longer term**. In evidence, FEI states it has completed preliminary analysis to understand the admissible limits for hydrogen blending on its existing natural gas infrastructure and end-use customer equipment and applications. FEI states that the "average service life (ASL) of FEI's transmission mains, which includes each of the CTS pipelines, is 65 years as determined in FEI's most recent 2017 Depreciation Study" and that the next depreciation study will be completed prior to 2025.
>
> Participants are requested to restrict their submissions to the issues canvassed in Panel IR No. 1, namely, the issue of hydrogen blending in FEI's CTS System. Parties are also encouraged to provide submissions on the impact, if any, that this should have on the depreciation rate and term for the project's assets. [Emphasis added]

FEI notes that the TLSE and the CTS TIMC projects are intended to improve resiliency and system integrity, and are necessary to provide ongoing safe and reliable service to existing customers (i.e., not to provide increased capacity).

39.5 Please confirm that expected changes in system capacity do not represent a regulatory risk, but are instead a demand risk, which is discussed and accounted for earlier in FEI's submissions along with the political risk.

Response:

Not confirmed.

As explained in FEI's business risk evidence, when performing risk analysis, other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category. In other words, in certain cases, some level of risk overlap may be inevitable. Certain

[28] Exhibit A-20 in the Certificate of Public Convenience and Necessity for the Coastal Transmission System Transmission Integrity Management Capabilities Project.

developments, conditions or events can impact multiple risk categories and FEI believes that discussing the various risks that are driven by the same root causes is important to understand the business' overall risk profile. This highlights the interconnected nature of risk analysis and demonstrates the importance and magnitude of the impact of a risk category.

Nevertheless, in this case there is a distinction between the demand and operational aspects of system capacity upgrades and the regulatory risk due to uncertainty around regulatory approvals for FEI's initiatives to add to system capacity.

FEI's system capacity upgrade projects, such as the Okanagan Capacity Upgrade (OCU), are driven by the changes in demand in particular regions of FEI's service territory. From this perspective, these projects are necessary to meet regional energy needs of customers now and well into future. The inability to proceed with system capacity upgrades or similar resiliency projects presents FEI with additional operating risk since it limits FEI's ability to provide safe and reliable service to customers at all time, including peak demand periods.

Regulatory risk on the other hand relates to the regulatory discretion in approving and/or denying the utility's applications. While public policy and future demand are factors that may be considered in regulatory decisions, other factors such as cost of service and rate design considerations are more prominent. As indicated in the preamble, in an era of high inflation and climate emergencies, the regulators may be hesitant to approve projects that can lead to higher prices or system upgrades.

39.6 Would FEI describe the BCUC's approach to RNG as being reasonably supportive? Please explain why or why not.

Response:

The GGRR provides for the acquisition of RNG since 2017 and more recently in 2021, hydrogen, syngas and lignin, such that the BCUC has had limited discretion. However, on December 21, 2021, the BCUC initiated a public inquiry into the acquisition of RNG after approximately 5 years of allowing acquisitions through the GGRR. While FEI believes that the BCUC is generally supportive, the BCUC appears to question the regulation and how it should be interpreted.

39.7 Would FEI describe the UCA GGRR Prescribed Undertaking for RNG to be reasonably supportive? Please explain why or why not.

Response:

The GGRR prescribed undertaking for RNG allows the utility to acquire up to 30 PJs of RG at a maximum price starting at $31 per GJ for fiscal 2021 and 2022, escalating by All-items Consumer Price Index for British Columbia each year. This regulation is supportive but contains limits on volume that will hinder FEI's ability to meet GHG reduction targets within CleanBC's Roadmap to 2030.

Although the CEC has referred to the "UCA GGRR", FEI notes that the GGRR is not set out in the UCA.

Please also refer to the response to BCUC IR1 14.4.

39.8 Please discuss whether or not multi-year rates plans result in reduced regulatory risk compared to businesses without MRPs.

Response:

As explained in the responses to BCUC IR1 21.1 and 21.2, the impact of performance-based or multi-year rate plans on regulatory risk depends on the individual plans' components. Considering FEI's and FBC's own experience with both cost of service and PBR plans/MRPs, the regulatory risk associated with the two frameworks is similar.

40. Reference: Exhibit B1-9-8-1, Appendix A page 120

> FEI believes that, compared to the 2016 Proceeding, the risk associated with regulatory lag has experienced a notable increase. FEI has observed increased interest and active participation by Indigenous and environmental groups in regulatory proceedings, such as its CPCN applications for the Okanagan Capacity Upgrade and the Tilbury LNG Storage Expansion projects. Further, some Indigenous groups have suggested there is uncertainty with respect to the BCUC's statutory scope with respect to reconciliation and the duty to consult. These delays not only result in regulatory lag, but they can increase costs as well. An example of this is that FEI is currently developing interim measures to address the delay to approval of its Okanagan Capacity Upgrade project that has resulted from a longer than anticipated regulatory process, to ensure continued supply of gas to its customers in that region.

40.1 Please provide specific, quantifiable evidence that the Commission has had an increase in regulatory lag over the last five years.

Response:

FortisBC tracks the number of days/months between the filing of applications and the BCUC decision dates and has provided this information in Attachment 40.1 for each of FEI and FBC. The spreadsheet demonstrates that there has been an increase in regulatory lag for both FEI and FBC over the last five years (i.e., since the 2016 Proceeding) compared to the five years prior to the 2016 Proceeding. For FEI, the average number of days from when an application is filed to when a decision is issued has increased from 238 days to 309 days. For FBC, the average number of days has increased from 348 to 371. FortisBC notes that it has excluded filings which did not result in a regulatory process beyond BCUC staff IRs or letters of comment in order to be comparable between the two time periods (i.e., post 2016 Proceeding and pre 2016 Proceeding). As FortisBC explained in its response to CEC IR1 11.1, there has been a change in how routine filings are reviewed since the 2016 Proceeding which has resulted in the majority of utility filings being posted publicly on the BCUC's website.

41. Reference: Exhibit B1-8-1, Appendix A page 120 and 121

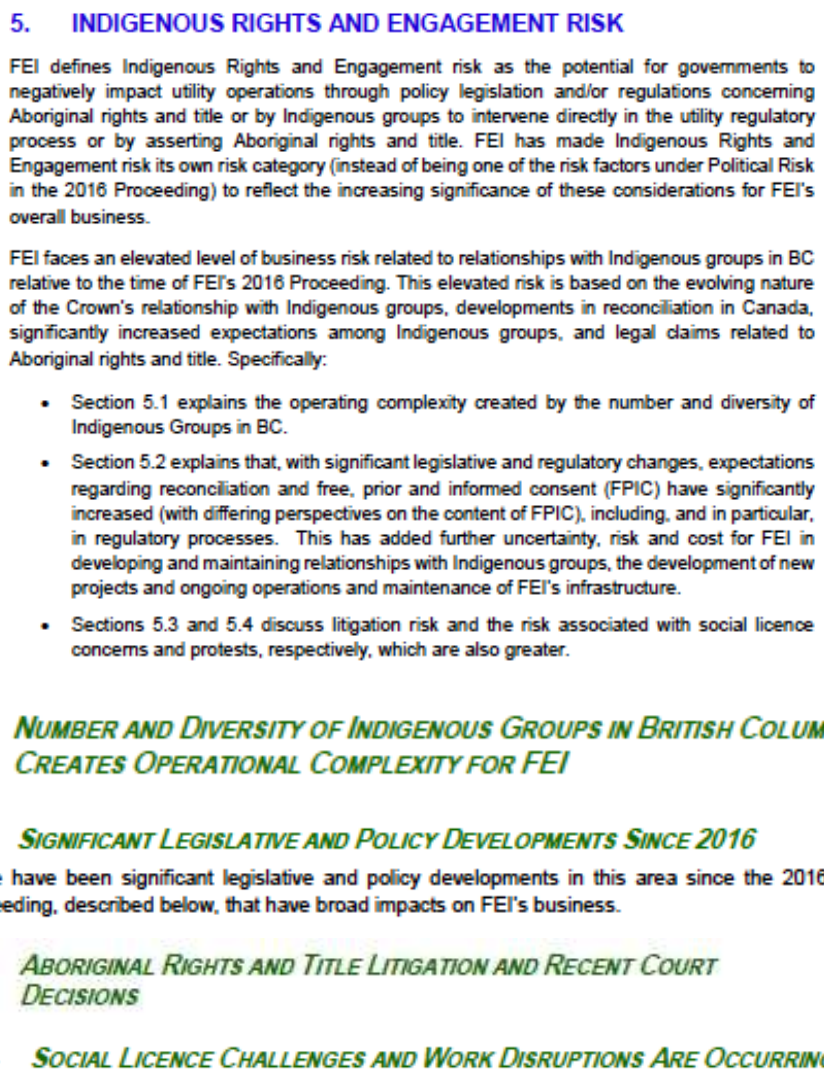
> ***10.1.2.3 Increasing Complexity and Cost of Projects Has Increased Dollars at Risk***
>
> While FEI is experiencing regulatory lag in the BCUC application filing and approval process, not all sources of regulatory lag relate to BCUC approval processes. FEI is seeing increased requirements for stakeholder consultation, environmental reviews, and Indigenous consultation which may also lead to increasing costs and delays in all regulatory approvals.
>
> In addition to higher and earlier costs resulting from changes to regulation regarding Indigenous groups, FEI is seeing increased costs from regulation in other areas. This includes heightened requirements for environmental work in advance of project development, including in some cases Environmental Assessments as described in Section 5.2.2, and fees and requirements for monetary contributions from municipalities as described in Section 9.4. In some cases, the resistance from municipalities has led to higher legal fees as municipalities are increasingly challenging the authority of the BCUC and utilities to undertake infrastructure projects in their boundaries.

41.1 Please confirm that ratepayers typically pay for stakeholder consultation, environmental reviews, indigenous consultation through their rates etc.

Response:

The types of costs being described on pages 120 and 121 of Appendix A are pre-CPCN expenditures. FEI typically requests approval to record these types of expenditures in a deferral account, either as part of the CPCN application, or in advance of the CPCN application if the forecast costs are expected to be significant and the timing of when the costs are expected to be incurred is well in advance of filing the CPCN. Historically, FEI has typically filed for deferral account approval as part of the CPCN application and has been granted approval both to establish the deferral account and to recover the costs in the deferral account from ratepayers. However, as explained in Section 10.1.2.3 of Appendix A, the increased requirements to perform environmental and consultation activities well in advance of filing CPCNs means that FEI is required to incur more costs earlier on in the project development process. Since these costs may not have received deferral account approval from the BCUC and, even if deferral account approval has been received, recovery of the deferral account costs may not yet have been determined, FEI's risk of not recovering these costs increases.

42. Reference: Exhibit B1-8, Appendix A, Section 5



5. INDIGENOUS RIGHTS AND ENGAGEMENT RISK

FEI defines 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 to intervene directly in the utility regulatory process or by asserting Aboriginal rights and title. FEI has made Indigenous Rights and Engagement risk its own risk category (instead of being one of the risk factors under Political Risk in the 2016 Proceeding) to reflect the increasing significance of these considerations for FEI's overall business.

FEI faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of FEI's 2016 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. Specifically:

- Section 5.1 explains the operating complexity created by the number and diversity of Indigenous Groups in BC.
- Section 5.2 explains that, with significant legislative and regulatory changes, expectations regarding reconciliation and free, prior and informed consent (FPIC) have significantly increased (with differing perspectives on the content of FPIC), including, and in particular, in regulatory processes. This has added further uncertainty, risk and cost for FEI in developing and maintaining relationships with Indigenous groups, the development of new projects and ongoing operations and maintenance of FEI's infrastructure.
- Sections 5.3 and 5.4 discuss litigation risk and the risk associated with social licence concerns and protests, respectively, which are also greater.

5.1 NUMBER AND DIVERSITY OF INDIGENOUS GROUPS IN BRITISH COLUMBIA CREATES OPERATIONAL COMPLEXITY FOR FEI

5.2 SIGNIFICANT LEGISLATIVE AND POLICY DEVELOPMENTS SINCE 2016

There have been significant legislative and policy developments in this area since the 2016 Proceeding, described below, that have broad impacts on FEI's business.

5.3 ABORIGINAL RIGHTS AND TITLE LITIGATION AND RECENT COURT DECISIONS

5.4 SOCIAL LICENCE CHALLENGES AND WORK DISRUPTIONS ARE OCCURRING

42.1 FEI provides an overview of the various risks faced by FEI related to Indigenous rights and engagement risks. Please refine the evaluation of FEI's Indigenous Rights and Engagement risk to relative risk for other corporations, and identify key differences with other energy corporations in Canada which would reasonably be considered as alternative investments.

Response:

FEI's risks related to Indigenous rights and engagement differ from many other Canadian energy corporations due to the Aboriginal and treaty rights landscape in BC, and the nature of FEI's infrastructure and operations.

The Indigenous Rights and Engagement risk in BC relative to other energy corporations across Canada is inherently different due to the reasons articulated in FEI's evidence, including the existence of a greater number of Indigenous groups in BC, the lack of treaties, and the early adoption of the *Declaration of the Rights of Indigenous Peoples Act*, which seeks to bring all BC legislation in alignment with the United Nations Declaration of the Rights of Indigenous Peoples.

As compared to other energy corporations in BC and elsewhere, many do not have infrastructure which requires linear corridors versus site-specific impacts (i.e., an energy extraction or production facility), thereby requiring FEI to engage and potentially accommodate multiple Indigenous groups that have shared (or overlapping and contested – depending on the relationships between the groups) territories. For example, FEI's infrastructure crosses the traditional territory of over 150 Indigenous groups' traditional territory.

Finally, FEI and FBC face similar levels of Indigenous Rights and Engagement risk, due to both being located in areas of BC largely not covered by treaties and the nature of the land use required for developing and maintaining primarily linear infrastructure.

42.2 Please identify any significant risk reduction projects and or environmental GHG reduction projects, which indigenous people have blocked from proceeding.

Response:

FEI is unclear on the question and whether it is referring specifically to FEI projects and what is defined as a risk reduction project. However, the question implies uniform Indigenous support for, or non-opposition to, projects that reduce emissions or significantly reduce risks to FEI. While it has been FEI's experience that Indigenous groups consider factors like emissions reductions as a factor in their decision-making, many Indigenous groups are more concerned about the extent to which cumulative impacts of development in their traditional territories infringe on their Aboriginal or Treaty rights.

As discussed in Section 5.3 of Appendix A, the Blueberry River First Nation, Thomas and Saik'uz First Nation and West Moberly First Nation cases each provide illustrative examples of Indigenous concerns regarding cumulative impacts and opposition to project development activities in their traditional territories, regardless of whether those projects will ultimately reduce emissions; to develop gas for use as LNG to displace higher emitting fuels in other countries or to construct or maintain facilities that produce clean hydroelectricity.

42.3 Please confirm that FEI supports fulsome consultation with indigenous people in regard to any projects and or services it intends to provide.

1
2 **Response:**

3 Although the duty to consult rests with the Crown, FEI believes strongly in engaging early and
4 meaningfully with Indigenous groups in circumstances where their Aboriginal rights and title are
5 potentially affected by Crown conduct.

43. Reference: Exhibit B1-8-1, Appendix A Section 6

> **6. ENERGY PRICE RISK**
>
> Energy prices impact a utility's business risk because price is among the factors that can influence consumer energy choices. Electricity remains the primary alternative available in British Columbia for space and water heating.[110] There are a number of factors that impact the price competitiveness of natural gas in BC relative to electricity.[111] They include:
>
> - Natural gas commodity price;
> - Natural gas commodity price volatility; and
> - Price competitiveness, including the impact of increasing carbon tax and an increased share of higher priced Renewable Gas in FEI's gas supply portfolio as well as a consideration of the relative installation costs of gas appliances compared to electric appliances.

43.1 Please provide an overview of BC Hydro electricity rates over the last 10 years, and expected rates forward for the next 10 years.

Response:

FortisBC provides the following 10 year electricity rate history for BC Hydro residential rates; FortisBC does not have access to 10 years of history for other rate schedules. FortisBC does not have information on BC Hydro's expected rates for the next 10 years beyond what has been filed by BC Hydro in its F2023-F2025 Revenue Requirements Application in Appendix II of Exhibit B-2-1.

BC Hydro Residential Rate History for RS 1101 (Bi-monthly)

Year	Basic Charge (per Day)	Energy Charge (First 1,350 kWh)	Energy Charge (Over 1,350 kWh)	Deferral Account Rate Rider
F2012	$0.1448	$0.0667	$0.0962	2.50%
F2013	$0.1505	$0.0680	$0.1505	5.00%
F2014	$0.1527	$0.1034	$0.0690	5.00%
F2015	$0.1664	$0.0752	$0.1127	5.00%
F2016	$0.1764	$0.0797	$0.1195	5.00%
F2017	$0.1835	$0.0829	$0.1243	5.00%
F2018	$0.1899	$0.0858	$0.1287	5.00%
F2019	$0.1956	$0.0884	$0.1326	5.00%
F2020	$0.2090	$0.0945	$0.1417	0.00%
F2021	$0.2056	$0.0930	$0.1394	0.00%
F2022	$0.2077	$0.0939	$0.1408	0.00%

FORTISBC

44. Reference: Exhibit B1-8, page 17 and page 18 and Exhibit B1-8-1, Appendix B, page 11

- *Business Profile*: FBC is a fully integrated electric utility that owns and operates hydroelectric generating plants, high voltage transmission lines, and a network of distribution assets in the southern interior of BC. FBC's structure as a fully-integrated electric utility contributes to a higher risk profile than for 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. 25 percent of revenue and more than 30 percent of load is attributable to two customer classes, Industrial and Wholesale, a significant number of which have the ability to receive service from alternate sources of supply with only limited notice. Despite the slight increase in FBC's customer profile risk due to a higher share of the Industrial sector in the company's load and revenue profile, FBC has assessed the overall business profile risk to be similar to what was assessed in the 2013 Proceeding.

44.1 Please provide examples of electric and gas distribution only utilities operating in Canada which could be considered to be of similar size or are the closest in size to FEI and FBC.

Response:

For FBC, most of the similar size distribution-only electric utilities in Canada are municipal owned utilities. The following provides a list of some of these utilities. Note that FBC has generation and transmission assets as well as distribution:

Electric Utilities			
Utility	**Ownership**	**Province**	**Web Address**
Energy+ Inc.	Municipal	ON	https://www.energyplus.ca/en/about-us/about-us.aspx
Burlington Hydro Inc.	Municipal	ON	https://www.burlingtonhydro.com/about/bhi-the-company.html
Oakville Hydro Electricity Distribution Inc.	Municipal	ON	https://www.oakvillehydro.com/index.html
Hydro-Sherbrooke	Municipal	QC	https://www.sherbrooke.ca/fr/hydro-sherbrooke
ENWIN Utilities Ltd.	Municipal	ON	https://enwin.com/
Kitchener-Wilmot Hydro Inc.	Municipal	ON	https://www.kwhydro.on.ca/en/our-company.asp

Electric Utilities			
Utility	**Ownership**	**Province**	**Web Address**
Saskatoon Light & Power	Municipal	SK	https://www.saskatoon.ca/services-residents/power-water-sewer/saskatoon-light-power/about-us
Veridian Connections Inc.	Municipal	ON	https://www.veridian.on.ca/
London Hydro Inc.	Municipal	ON	https://www.londonhydro.com/about-us/about-london-hydro
ATCO Electric Ltd.	Inv. Owned	AB	https://electric.atco.com/en-ca/about.html

As shown in Figures 53, 54 and 57 of Concentric's evidence (Appendix C), most of the investor-owned electric utilities in FBC's Canadian and U.S proxy groups are larger than FBC.

The number of gas distribution utilities in Canada is much smaller. Figure 47 in Concentric's evidence provides a list of the four major gas distribution utilities in Canada. The closest in size to FEI in terms of customers and throughput is ATCO Gas.

44.2 Please provide the alternative sources of supply available to industrial and wholesale customers with limited notice.

Response:

The most likely sources of third-party supply for eligible wholesale and industrial customers are wholesale market purchases through the Mid-Columbia trading hub, as well as generators within and outside the FBC service area including independent power producers or industrial co-generation.

44.2.1 Please explain if the alternative sources of supply risk are significantly different or riskier for wholesale customers than for the other distribution utilities of similar size.

Response:

FBC is unclear as to what this question is asking. In Appendix B to FortisBC's evidence, FBC has identified that it is subject to business risk arising from the ability of its wholesale customers to take third-party supply, thereby reducing the amount of power purchased from FBC. If the question is seeking FBC's views on whether having this alternate source of supply option carries a risk for wholesale customers that is greater than the case where other distribution utilities had a similar opportunity, then the relative risks would depend entirely upon the terms and conditions faced by those utilities and cannot be answered in the hypothetical. FBC does not have customers that are distribution utilities that are not also wholesale customers so a comparison between these situations is not possible. If the question is seeking information on the alternative sources available for wholesale customers under other distribution utilities, FBC does not have information that would enable it to comment.

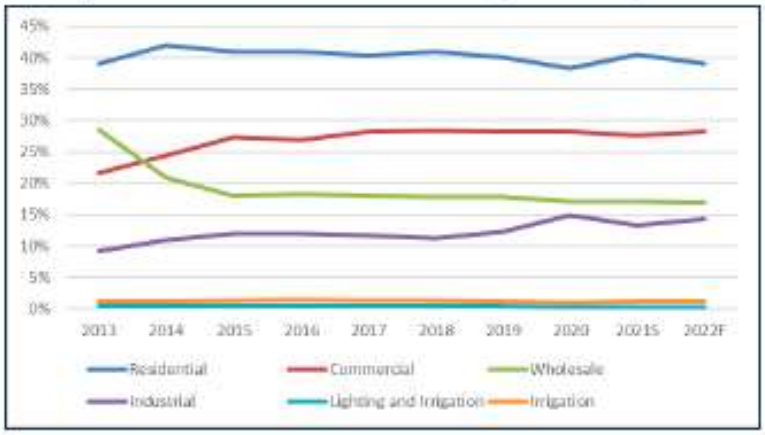
45. Reference: Exhibit B1-8, page 11 and page 12

2.3 SHIFTING CUSTOMER PROFILE PRESENTS DIFFERENT CHALLENGES

The risk profile of a utility is impacted by its overall customer class composition - that is, the proportion of total customers represented by a single broad customer type, such as residential, commercial, Industrial, and Wholesale groupings. Particularly relevant to FBC, the risk profile is also impacted by the proportion of total load that one particular customer group may comprise, even if the total number of customers in that group may be small. Generally, while diversity of customer characteristics is desirable from a risk perspective, a concentration of a significant proportion of overall load among a small number of customers is not. As shown in the figure below, FBC's customer profile by account type is typical of most utilities in that the majority of customers are in the residential sector. However, as shown in Figure B2-1 and as compared to the 2013-2014 period, the share of FBC's overall load profile in the Industrial sector is on an upward trajectory, increasing from 9 percent in 2013 to 14 percent in 2022. This trend leads to an increase in FBC's risk profile since Industrial load is more volatile and more prone to economic downturns. For instance, in 2019 FBC's Industrial load grew by 23 percent but the economic crises brought on by the COVID-19 pandemic caused Industrial load to drop by 11 percent in 2020.

Compared to the 2013 Proceeding, FBC assesses that the increase in share of Industrial load in the company's load profile results in a slight increase to the risk associated with its customer profile.

Figure B2-1: The Trend in FBC's Load Profile by Customer Segment[18]



45.1 FBC states that the share of load in the industrial sector is on an upward trajectory, which is increasing risk. Please provide the total $ value of load, and % of dollar value of load in each segment for each year over the last 5 years.

Response:

FBC identified an error in Figure B2-1; please refer to the response to BCOAPO IR1 11.4 for the revised Figure B2-1.

As requested, the total normalized[29] revenue by class along with the revenue percentages from 2017 to 2021 are provided in the table below.

[29] Please note that only the Residential, Wholesale, and Commercial classes are normalized since they exhibit a

Revenue by Class from 2017 to 2021

Normalized Revenue ($000)s	2017		2018		2019		2020		2021	
Residential	$179,508	50%	$186,922	51%	$176,150	48%	$189,204	51%	$198,165	50%
Commercial	$ 90,024	25%	$ 91,087	25%	$ 93,846	26%	$ 94,198	25%	$102,334	26%
Wholesale	$ 47,988	13%	$ 47,920	13%	$ 48,160	13%	$ 47,433	13%	$ 50,187	13%
Industrial	$ 31,101	9%	$ 30,785	8%	$ 39,756	11%	$ 35,467	10%	$ 37,841	10%
Lighting	$ 3,554	1%	$ 3,078	1%	$ 2,316	1%	$ 3,106	1%	$ 2,177	1%
Irrigation	$ 3,424	1%	$ 3,510	1%	$ 3,042	1%	$ 2,454	1%	$ 3,967	1%
Total Sales	$355,599	100%	$363,302	100%	$363,270	100%	$371,862	100%	$394,671	100%

The table above shows that FBC's Industrial revenues have grown by 22 percent over the five year period; increasing from 9 percent to 10 percent of total revenue.

The referenced section of Appendix B was comparing current Industrial load to 2013 (when FBC last filed cost of capital evidence). When compared to 2013, FBC's Industrial revenues have grown by 40 percent; increasing from 9 percent to 10 percent of total revenue. For the total energy load profiles from 2017 to 2021, please refer to the response to CEC IR1 45.3.

45.2 Please also provide the contribution to net of cost of service revenue requirements for each of the rate classes over the 2013 to 2021 period with a forecast for 2022.

Response:

FBC has provided the percentage of the total revenue provided by each rate class in the response to CEC IR1 45.1. Therefore, FBC assumes that this question is requesting the revenue to cost ratios for each rate class as determined through a Cost of Service Analysis (COSA). FBC conducts a COSA on a periodic basis only and, as such, does not have annual numbers available. The most recent COSAs were filed with the BCUC in 2009, 2017, and 2020. No forecast for 2022 is available. The information for the most recent COSAs is below.

Historic Revenue to Cost Ratios

	2009 COSA	2017 COSA	2020 COSA
Residential	93.3	98.4	99.7
Small Commercial	107.6	102.2	101.5
Commercial	128.2	104.7	99.5
Industrial – Primary	112.8	104.0	105.7
Industrial – Transmission	98.7	107.0	110.4
Lighting	84.4	92.2	84.9
Irrigation	88.0	97.2	96.5

statically significant correlation to Heating Degree Days and Cooling Degree Days in the service area.

	2009 COSA	2017 COSA	2020 COSA
Wholesale - Primary	94.0	96.7	96.7
Wholesale - Transmission	95.1	103.9	95.8

45.3 Please provide the total volume of load in each rate class over the last five years.

Response:

The total energy load volumes by class (normalized for residential, commercial and wholesale classes) as well as the class load percentage of the total from 2017 to 2021 are provided below.

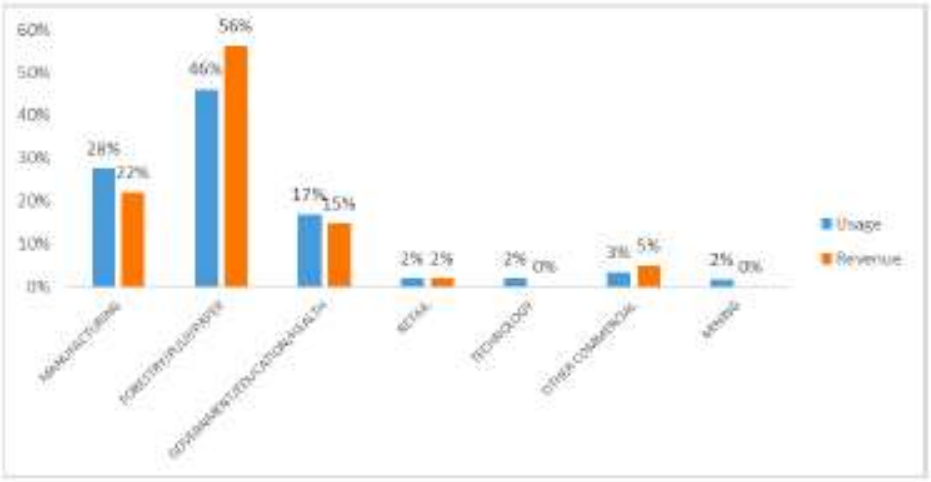
Normalized Energy Load Volumes by Class and Percentage of Total from 2017 to 2021

Energy (GWh)	2017		2018		2019		2020		2021	
Residential	1,320	41%	1,313	40%	1,266	38%	1,347	40%	1,330	39%
Commercial	915	28%	926	28%	932	28%	922	28%	960	28%
Wholesale	574	18%	585	18%	566	17%	569	17%	566	17%
Industrial	363	11%	403	12%	495	15%	441	13%	472	14%
Lighting	16	0%	13	0%	11	0%	11	0%	44	1%
Irrigation	42	1%	39	1%	36	1%	37	1%	10	0%
Total	3,230	100%	3,278	100%	3,306	100%	3,328	100%	3,381	100%

46. Reference: Exhibit B1-8-1, Appendix B, page 30

Figures B7-1 and B7-2 below illustrate the changes to the company's load and revenue diversity from 2013 to 2020. In 2013, 46 percent of the load and 56 percent of the revenue attributable to the largest 20 customers was in the forestry industry, which included 9 customers. The other two significant contributors to load were in the manufacturing and institutional sectors, made up of government, education and health related accounts. In 2020, these aforementioned industries remained as key factors in overall load, and the emergence of the technology sector is driven primarily by a single cryptocurrency customer.

Figure B7-1: Industry of FBC's Top Twenty Industrial Customers by Load in 2013



46.1 Please provide data for comparative small distribution utilities with regard to the industrial class of customers and the concentration of demand in given sub-segments.

Response:

FBC does not have similar data from other utilities and has been unable to find any publicly available information that would enable it to respond to this request.

47. Reference: Exhibit B1-8, page 18 and Exhibit B1-8-1, Appendix B page 13

> - *Economic Conditions*: The current Canadian economic environment continues to be dominated by uncertainty. FBC's assessment of major economic indicators indicates that BC is recovering from the pandemic lows. Nevertheless, 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. In addition, compared to other larger utilities, FBC's smaller size and dependence on highly cyclical industrial load in one or two sectors contribute to FBC's higher economic related risk.
>
> However, as confirmed by Moody's, economic conditions pose an elevated level of risk to smaller utilities. This is because the smaller utilities have fewer abilities to diversify their operations and protect themselves against economic-driven volatility.
>
> Moody's states:
>
> > While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including Industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility ... Economic diversity is typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry ... An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.[18]
>
> As such, FBC submits that although its economic conditions are similar to FEI, FBC is faced with slightly higher risk given its small size and exposure to highly cyclical Industrial load in one or two sectors (forestry and cryptocurrency mining).

47.1 Please confirm that the pandemic has caused economic uncertainty world-wide and is not unique to FortisBC.

Response:

Confirmed. The above discussion was comparing the impacts of economic conditions on FortisBC in previous proceedings to now; not a comparison to the impacts of economic conditions on FEI and FBC to other utilities or companies.

47.2 Is it fair to say that FortisBC's economic risk would be similar to other small electric utilities operating in Canada? Please explain why or why not.

Response:

As stated in the response to CEC IR1 31.5, in today's economic environment, the COVID-19 pandemic and its impact on supply chain issues as well as record high inflation are the prominent economic risk events that are impacting all utilities. However, the magnitude of impact for these risk events depends on the individual circumstances of each utility. For example, the pandemic had a bigger and longer negative impact in some jurisdictions or some utilities may be facing higher regional inflation than others. Therefore, FBC believes that it is fair to say that FBC's economic risk is comparable to other small electric utilities in Canada; however, it cannot comment on the degree of comparability without more detailed study of the individual utilities' circumstances.

48. Reference: Exhibit B1-8-1, Appendix B, page 11 and Exhibit B1-8, Appendix B page 18

> - *Political Risk*: The government push for electrification of the BC economy 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, and government's ability to subsidize BC Hydro customers is not a path open to FBC. Overall, however, FBC assesses that its political risk is lower than what was assessed in the 2013 Proceeding.
>
> From that perspective, electric utilities in the province face a lower risk, although a policy-driven consumer shift from gas consumption to electricity is not without its complications for FBC. In the shorter-term, increased load would be expected to have a favourable impact on rates, so long as there is capacity on the FBC system. However, heating load typically has a low load factor, peaking in winter when capacity is most constrained. A drastic increase in low load factor customer consumption of electricity drives additional investment in more capital infrastructure, which increases utility costs and rates for existing customers. Much like negative growth is a large risk factor to a utility, rapid policy-driven customer migration from natural gas to electricity increases risk and presents operational challenges for FBC which has limited resources in a small geographical service territory.

48.1 Please elaborate on the specific challenges that FBC is expecting with respect to its load as a result of electrification, and how this is expected to affect FBC financially.

Response:

Electrification can provide benefits and challenges for FBC in serving its customers. Electrification, including for home and business space and water heating and relating to transportation, can increase the load on FBC's system, which, if it occurs at a manageable pace, can improve utilization of the FBC system and enable supporting infrastructure, and its associated costs, to be added gradually over time, thereby minimizing rate increases for all customers. However, as discussed in Section 4.1 of Appendix B, a drastic increase in low load factor customer consumption of electricity can drive significant additional investment in more capital infrastructure to support the new capacity requirements, which increases costs for FBC and thus rates for existing customers. This electricity demand could include rapid customer migration from natural gas or other fuels to electricity as well as sudden and significant growth in home EV charging. Increases in FBC's rates affect its competitiveness with other utilities, like BC Hydro, and other sources of electricity, such as rooftop solar generation. This can lead to customer migration which reduces overall utilization of FBC's system and further adds to FBC's challenges in maintaining rate competitiveness. In addition to the potential cost and rate pressures mentioned, EV charging could also present operational challenges in terms of overloading distribution transformers with the concentration of EVs in a relatively small area on the FBC system, as discussed in Section 7.1.2 of Appendix B. The potential impacts on customer rates and FBC's competitiveness are uncertain and will depend on the demand growth and its impacts on the additional resources needed to meet this growth and operational challenges. Therefore, FBC is not able to quantify the potential financial impacts at this time.

48.2 Would FBC agree that FBC's political risk is lower than FEI's? Please explain.

Response:

Yes. A review of FBC's past and current risk evidence indicates that FBC's political risk is lower than FEI. For instance, in the 2014 Stage 2 GCOC proceeding, FBC stated that it "has slightly lower political risks as compared to FEI".

Similarly, FBC's business risk evidence (Appendix B) states that an important implication of government policies is that in BC, "electrification" is positioned as the preferred option to reduce emissions. From that perspective, electric utilities in the province face a lower risk than gas utilities. FBC's evidence further concludes that, on balance, its policy-related risk is lower than what was assessed in the 2013 Proceeding. In comparison, the electrification of the economy, particularly in the building sector, is a significant long-term risk to FEI and FEI submits that compared to 2016 its political risk has significantly increased. As such, FBC concludes that its political risk is lower than that of FEI.

48.3 Please discuss whether FBC has been able to mitigate the risk of load variability through its PPA agreements with BC Hydro and others.

Response:

FBC has been able to mitigate the risk of shorter-term load variability through the BC Hydro PPA. This is because FBC has sufficient flexibility to adjust energy purchase amounts to respond to unexpected variations in load. This flexibility is not unlimited, but it is sufficient for normal operational purposes combined with FBC's energy storage capabilities under the Canal Plant Agreement and wholesale market access.

Longer-term load risk is addressed through the LTERP planning process. This may include higher purchases under the BC Hydro PPA or new supply sources.

49. Reference: Exhibit B1-8, page 15

> Although this study considered the energy needs of the entire province and not just that of FBC's service territory, the same conclusion can be drawn for FBC, that over-reliance of government policy on electrification as the only solution to the climate change crisis can lead to increased costs to the utility and its customers.
>
> BC Hydro, with its Crown status, has access to a provincial funding backstop that it sometimes uses to recover costs, keep its rates low and minimize its borrowing costs. The same does not apply for FBC as it does not have the ability to use taxpayer funds to cover costs. The BC government's 2019 decision to write-off BC Hydro's rate smoothing deferral account is one recent example of BC Hydro being able to utilize taxpayers to cover costs. On February 14, 2019, the BC government issued a news release stating that... "as part of transitioning to enhanced oversight, government has accepted a recommendation from the review for BC Hydro to stop using the rate-smoothing regulatory account and to write off its balance to zero in 2018-19. This will limit rate increases and relieve ratepayers of the burden of directly paying off $1.1 billion in deferred costs over the next five years.[17]" The government's decision to socialize $1.1 billion of BC Hydro's cost both reduces FBC's price competitiveness with BC Hydro, as well as forces FBC's ratepayers to pay directly for their own utility services, as well as a portion of BC Hydro's bill paid through taxes. As such, the government's ability and willingness to subsidize BC Hydro customers is an increased risk to FBC.

49.1 Please discuss how the potential for increased prices as a result of electrification and fuel switching could impact FortisBC negatively and quantify the potential impacts.

Response:

Please refer to the response to CEC IR1 48.1.

49.2 Is the risk of price increases more likely to result in demand risk, rather than political risk? Please explain why or why not.

Response:

As explained in FBC's business risk evidence, when performing risk analysis, other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category. In other words, in certain cases, some level of risk overlap may be inevitable. Certain developments, conditions or events can impact multiple risk categories and FBC believes that discussing the various risks that are driven by the same root causes is important to understand the business' overall risk profile. This highlights the interconnected nature of risk analysis and demonstrates the importance and magnitude of the impact of a risk category.

FBC 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. From this perspective, BC government's ability and willingness to subsidize BC Hydro is a political risk because its root cause is policy driven. Nevertheless,

socialization of BC Hydro's costs also has price risk and demand/market risk implications since it will reduce the price differential between FBC's rates and BC Hydro rates which in turn will impact FBC's ability to attract and/or retain customers, particularly customers with greater portability capabilities.

50. Reference: Exhibit B1-8, page 18 and Exhibit B1-8-1, Appendix B page 16

> - *Indigenous Rights and Engagement*: FBC has made Indigenous Rights and Engagement risk its own category (instead of being one of the risk factors under Political Risk) to reflect the increasing significance of these considerations for FBC's overall business. FBC defines Indigenous Rights and Engagement risk as the potential for utility operations to be negatively 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, FBC 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 2013 Proceeding. Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FBC operates. Combined with regulatory updates that have increased consultation requirements and included a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FBC faces an elevated risk of cost escalation, project delays and/or projects being denied approval.
>
> FBC faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of FBC's 2013 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. Specifically:
>
> - With the significant legislative and regulatory changes described in Section 5.2 of FEI's business risk evidence (Appendix A), expectations regarding reconciliation and free, prior and informed consent (FPIC) have significantly increased (with differing perspectives on the content of FPIC), including, and in particular, in regulatory processes. This has added further uncertainty, risk and cost for FBC in developing and maintaining relationships with Indigenous groups, the development of new projects and ongoing operations and maintenance of FBC's infrastructure.
> - Litigation risk and the risk associated with social licence concerns and protests, discussed in Sections 5.3 and 5.4 of FEI's business risk evidence (Appendix A) respectively, are also greater.

50.1 Please describe how the Indigenous Rights and Engagement risk can be evaluated against other electric distribution companies, and against the risk faced by FEI.

Response:

Please refer to the response to CEC IR1 42.1.

51. Reference: Exhibit B1-8, page 19

> - *Demand/Market*: Emerging technologies can provide challenges for FBC. In particular, alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider, while new load requirements, such as EV charging, can conversely increase the load requirements of FBC. Both situations create potential risks for higher costs and to grid integrity and managing the timing of load on the system to avoid peak demand impacts. Also, FBC continues to face demand risk in its Wholesale and Industrial customer segments. This is because FBC's Wholesale and some Industrial 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. BC Hydro, whose Industrial and Wholesale rates are competitive with FBC's, continues to be an alternative for FBC's eligible customers. FBC faces risk associated with being highly dependent on load concentration in only two industries – forestry and cryptocurrency mining. The growing share of Industrial load in FBC's load profile contributes to FBC's higher risk since Industrial load is more volatile. Compared to 2013, FBC's residential and commercial UPC values have been on a downward trajectory while Industrial UPC has increased. 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's demand risk is similar to what was assessed in the 2013 Proceeding.
>
> **7.1.2 EV Charging Load Presents an Opportunity and Challenges**
>
> With supportive government policies, EV charging load is expected to increase in the coming years. All else equal, additional EV charging load improves FBC's risk since it would increase FBC's load which helps to mitigate rate pressures. However, increasing EV load in a short period of time or not being able to manage EV charging during peak demand periods can create its own challenges.
>
> FBC faces an increasing challenge with respect to the integrity of its grid due to incremental peak demand imposed by EV loads. This demand depends on the size of the on-board battery, the owners' driving patterns, the charging strategy and the charger characteristics. With improvements in battery efficiency and longer ranges on an increasing number of EV models, customers will require higher electricity demand than that allowed by charging through a conventional 120 V (level 1) outlet. Several electric vehicle chargers on one residential street or a concentration of commercial enterprises utilizing electric fleet vehicles could overload the local distribution transformer unless demand management measures are implemented to shift charging times from peak periods and prevent a possible overload.

51.1 Please confirm that the demand changes from EV charging do not constitute a significant demand risk, but could result in operational risk or supply risk.

Response:

Please refer to the response to CEC IR1 48.1.

51.2 Please confirm that FBC expects to be able to meet the EV demands or explain why not.

Response:

Confirmed. EV demands will be met if FBC is able to upgrade infrastructure, implement EV charging shifting programs, and obtain regulatory support for these initiatives.

51.3 Would FBC agree that its demand risk is reducing as a result of electrification and EV charging? Please explain why or why not.

Response:

Please refer to the response to BCUC IR1 31.1.

52. Reference: Exhibit B1-8, page 19 and Exhibit B1-8-1 page 30

> • *Demand/Market*: Emerging technologies can provide challenges for FBC. In particular, alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider, while new load requirements, such as EV charging, can conversely increase the load requirements of FBC. Both situations create potential risks for higher costs and to grid integrity and managing the timing of load on the system to avoid peak demand impacts. Also, FBC continues to face demand risk in its Wholesale and Industrial customer segments. This is because FBC's Wholesale and some Industrial 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. BC Hydro, whose Industrial and Wholesale rates are competitive with FBC's, continues to be an alternative for FBC's eligible customers. FBC faces risk associated with being highly dependent on load concentration in only two industries – forestry and cryptocurrency mining. The growing share of Industrial load in FBC's load profile contributes to FBC's higher risk since Industrial load is more volatile. Compared to 2013, FBC's residential and commercial UPC values have been on a downward trajectory while Industrial UPC has increased. 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's demand risk is similar to what was assessed in the 2013 Proceeding.
>
> As a general principle, if a utility's customer base is dominated by a small number of industries or large customers, the downturns in, or failures of, any one of those industries or customers is more likely to have a material impact on the utility than downturns or failures in an industry that accounts for a smaller proportion of the utility's overall load. FBC faces risk associated with being highly dependent on single large customers in only two industries – forestry and cryptocurrency mining.

52.1 Please explain how cryptocurrency has affected FBC's load over the last 5 years.

Response:

A portion of this response is confidential and has been redacted pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. The redaction is necessary to maintain confidentiality over customer information for which FortisBC does not have the authority or permission to disclose, and may negatively impact customers if it were publicly disclosed. Given the private nature of the information, FortisBC submits that only the BCUC should have access to the unredacted confidential version.

Since emerging as a load category, cryptocurrency mining has become a significant portion of FBC's industrial load. Please find below the percentage of total FBC overall and industrial load[30] represented by cryptocurrency mining since 2019, the first year the industry appeared.

Year	Total Annual Energy Load (GWh)	Percent of Total Load	Percent of Total Industrial Load
2019	[redacted]		
2020			
2021			

[30] Billed consumption as compared the load information contained in Section 3.4 of FBC's Annual Review of 2022 Rates.

52.2 Please provide FBC's net load changes over the last five years.

Response:

Please refer to the response to CEC IR1 45.3.

52.3 Please provide FBC's expectation for net load changes over the next five years, including and identifying all impacts such as solar generation reductions, and EV charging increases.

Response:

The information below has been drawn from the Reference Case load forecast in the FBC 2021 Long-Term Electric Resource Plan, Appendix G, Table 2.1 Gross Energy Load. This represents the most recent forecast that FBC expects to materialize over the next 5 years. This load forecast includes the EV charging impact, which is shown in a separate column in the table. Energy reductions due to customer-owned rooftop solar generation is not separately accounted for in the load forecast as it is inherently captured in the forecast methodology for the residential class.

Year	Gross Load (GWh)	Change from Previous Year (GWh)	EV Impact (GWh)
2023	3,787	(1)	18.5
2024	3,794	7	23.6
2025	3,855	61	29.1
2026	3,904	49	36.9
2027	3,957	53	47.0

53. Reference: Exhibit B1-8-1 Appendix B, page 41 and Exhibit B1-8, page 19

> FBC generates approximately 44 percent of its energy and approximately 28 percent of its capacity needs from its own hydro generating plants. The remainder of its supply comes from purchased power. FBC has long-term supply contracts with BC Hydro, Columbia Power Corporation, Brilliant Power Corporation and Waneta Expansion Power Corporation. These resources are sufficient to meet FBC's expected[38] capacity requirements until 2030 given the expiry of the Residual Capacity Agreement and FBC's ability to ramp up BC Hydro PPA nomination, despite the expiration of the Brilliant Expansion Agreement in 2027. More significantly, the PPA, under which FBC has firm power supply access to capacity and energy at BC Hydro's embedded costs, expires in 2033. At this time, there is uncertainty that FBC will be able to renew these agreements and at similar costs. If FBC is not able to renew these agreements at similar costs, it may be required to enter into contracts with higher costs or require more costly resources which would increase rates for customers.
>
> - *Energy Supply*: The majority of FBC's supply risk has been mitigated through long-term, firm power purchase agreements; although, as these agreements expire, there is no guarantee that FBC will be able to renew them, or that they could be renewed at a similar cost. Furthermore, there is risk associated with FBC accessing supply from the wholesale market. FBC's access to the wholesale market is dependent on FBC's access to Teck's Line 71. FBC has no transmission facilities that connect directly with markets outside of BC, and is dependent on this availability of third-party transmission capacity to serve its customers' growing demand and the potential for increased likelihood of severe weather events such as the June 2021 heat dome and the new all-time peak demand in December 2021. In addition, FBC-owned generating plants are located within the Kootenay region, while most of FBC's customer load requirements are in the Okanagan. Failure of a plant generating unit would result in FBC needing to acquire replacement power which may not be available due to either lack of available supply or lack of available transmission. In addition, the replacement power, if acquired, could be at a significantly increased cost on the open market. Overall, FBC's risk in terms of energy supply is similar to 2013,

53.1 Please provide an assessment of FBC's supply risk relative to other small electric distribution utilities, and please consider the proportion of energy supply that may be considered to be within their control over the next ten years.

Response:

FBC does not have the information regarding other small electric utilities to undertake this analysis.

For a high level discussion regarding the comparison of FBC's supply risk with electric utilities in other jurisdictions, please refer to page 134 of Concentric's evidence (Appendix C).

54. Reference: Exhibit B1-8, page 20

> - *Operating*: 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 also exposed to operating risk related to the requirement that the generating units always be available to run for FBC to receive its capacity and energy entitlements as provided for under the Canal Plant Agreement. Failure of one or more of the generating units owned by FBC could potentially result in significant power supply costs to replace the lost entitlements. 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. 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 cyber-attacks 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.

54.1 Please discuss whether or not FBC can expect to experience a different level of operating risk since 2013 relative to other small distribution electric utilities.

Response:

FBC is not a distribution electric utility; it is a vertically integrated utility. Regardless, this question cannot be answered in the abstract without an understanding of the specific utility being referenced.

55. Reference: Exhibit B1-8, page 20

> - *Regulatory*: 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 is what is referred to in this section as regulatory risk. FBC has assessed its overall regulatory risk as higher than what was assessed in FBC's 2013 Proceeding, with certain risk factors increasing and others being similar. The BCUC's jurisdiction is confined to what is conferred by the UCA, but within that framework the BCUC has significant discretion in the exercise of those powers. 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 FBC with an opportunity to earn its fair return, or that necessary investments are not approved. The underlying regulatory framework remains the same, but there are new developments that merit note. There is uncertainty caused by the BCUC's decision to consider a more generic approach to deferral account financing treatment. The risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 Proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title.

55.1 Please elaborate on the 'more generic' approach to deferral account financing, and how that impacts the risk to FBC.

Response:

Please refer to the response to BCUC IR1 36.2.

55.2 Please provide any evidence available that FBC has experienced less fair regulatory processes than it has in the past, or that they are less fair than other similar small electric distribution companies.

Response:

There is no reference in the cited evidence to FBC experiencing less fair regulatory processes than in the past or less fair regulatory processes than other similar small electric utilities. Rather, FBC's comments in the passage in the preamble address the possibility of the BCUC's future decisions leading to undesirable outcomes for the company, irrespective of whether the processes that led to those undesirable outcomes were procedurally fair.

Effective Dates for Approved ROE and Capital Structure

56. Reference: Exhibit B1-8 page 51

> In line with the BCUC statements above and as further explained in FortisBC's March 29, 2021 letter (Exhibit B1-2), the effective date should depend on the timing and progress of the GCOC proceeding. If the regulatory timetable set by the BCUC will result in a decision in the first quarter of the year, then having an effective date of January 1 of that year could be appropriate. This would avoid having interim rates in place for an extended period of time, improve administrative and regulatory efficiency, and may reduce customer bill impacts. Further, avoiding an extended period of interim rates can mitigate some of the regulatory risk that investors face by virtue of not knowing the return on the invested capital until the decision is issued.
>
> Considering the BCUC established regulatory timetable in this Proceeding (Order G-288-21, dated October 6, 2021), FortisBC expects a decision on FEI's and FBC's cost of capital in this proceeding in the fourth quarter of 2022 or the first quarter of 2023. Therefore, FortisBC submits that given the above-mentioned conditions, an appropriate effective date for approved ROE and capital structure established in this Proceeding, is January 1, 2023.

56.1 If the timetable were to be delayed to the 2nd quarter of 2023, or if an appeal were launched, would FEI expect to extend the effective date, and continue with interim rates? Please explain.

Response:

Please refer to the responses to BCUC IR1 2.2 and 2.3.

Choice of Benchmark Utility

57. Reference: Exhibit B1-8 page 53

8. THE CHOICE OF THE BENCHMARK UTILITY FOR STAGE 2

Considering the BCUC's direction for each of FEI and FBC to file separate evidence, FortisBC submits that the BCUC can individually determine each of FEI's and FBC's appropriate allowed ROE and capital structure without reference to a Benchmark Utility. In this regard, the choice of the Benchmark Utility is a topic that is better addressed by other utilities to whom the Benchmark Utility approach applies.

As explained in FortisBC's Letter to BCUC dated July 21, 2021 (Exhibit B2-4), some of the relevant factors to consider in determining a Benchmark Utility are as follows:

1. **Availability of comparable proxy group**: The comparable investment principle is one of the three elements of the Fair Return Standard. Under this principle a fair and reasonable return should be comparable to the return available from the application of the invested capital to other enterprises of like risk. To achieve this legal requirement, cost of capital experts usually establish a proxy group of publicly traded comparable risk companies and use the proxy group's data as inputs in their financial models. Therefore, the availability of a listed comparable risk proxy group is a critical consideration for establishing the Benchmark Utility.
2. **Credit ratings**: The Benchmark Utility should preferably issue its own debt and have its debt rated by major credit rating agencies. This would provide the BCUC and other parties with an independent analysis of a utility's risk profile, albeit from the bondholder's perspective.
3. **Size of operation**: This factor is closely tied to the availability of a comparable proxy group discussed above. The majority of the publicly listed utilities are very large. It is therefore preferable that the Benchmark Utility shares characteristics with the proxy group and has a large operation. Further, a relatively large utility with diversity in customer base, asset composition and geographic scope is less likely to be susceptible to unique or specific risks that have a disproportionate impact on risk profile that may make comparisons more difficult.
4. **Stability of operation**: The Benchmark Utility needs to have stable operations and not be subject to takeovers or mergers that can drastically change its risk profile.
5. **Resources and expertise**: As explained above, preparation of cost of capital applications requires both specialized expertise, usually acquired through retaining external consultants, and significant internal resources. The capability of the Benchmark Utility to provide these resources without material rate impact to its ratepayers is another relevant consideration.
6. **Familiarity with and acceptance of the Benchmark Utility by other affected utilities**: Other affected utilities must be fairly familiar with the Benchmark Utility operation to be able to compare their risk with that of the benchmark. A general consensus among affected utilities around the appropriate Benchmark Utility will help to facilitate the process and increase the administrative efficiencies and avoid unnecessary controversies.
7. **Ownership**: The opportunity cost for a Crown corporation like BC Hydro is fundamentally different from that of investor-owned utilities. Considering that the majority of the utilities are investor-owned, the Benchmark Utility should be an investor-owned utility.

In conclusion, FEI's and FBC's allowed ROE and capital structure can and should be determined in the Stage 1 GCOC Proceeding on a stand-alone basis and without reference to the Benchmark Utility. The issue of whether FEI and/or FBC shall act as the Benchmark Utility in Stage 2 GCOC Proceeding needs to be addressed by other utilities to whom the Benchmark Utility approach applies. Nevertheless, FortisBC observes that there is a strong support for FEI to continue its role as the Benchmark Utility, although other options such as having two Benchmark Utilities are also possible.

57.1 Please confirm that investors do not invest in companies by comparing their current state to their historical state and environment, but instead compare them on a present and forward-looking basis to other available options.

Response:

Partially confirmed. FortisBC confirms that risk analysis is prospective in nature and that investors are primarily concerned about the future prospects of an investment. However, as explained in the BCUC's decision in the 2016 Proceeding, this does not mean that investors do not consider historical performance when choosing to make an investment:

> The Panel accepts FEI's argument that risk is prospective. In the Panel's view, the risk of earning ROE does not disappear in any given test year because of a utility's success in achieving it in prior years. However, this does not mean that an investor does not consider historical performance when choosing to make an investment but in doing so must accept that there is no certainty that past performance will be repeated in the future. [Underline Added]

For more discussions regarding an appropriate reference point for risk analysis please refer to the responses to BCUC IR1 4.3 and 36.1.

Automatic Adjustment Mechanism

58. Reference: Exhibit B1-8, page 56

> **9. AUTOMATIC ADJUSTMENT MECHANISM**
>
> Part of the scope of this proceeding, as noted in Appendix B to Order G-281-21, is to determine whether the re-establishment of a formulaic ROE AAM is warranted. If a return to the use of a formulaic ROE AAM is warranted, then BCUC further seeks evidence on: (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 (c) to whom the ROE AAM will apply.
>
> FortisBC continues to believe that a regulatory proceeding is preferable to the use of a mechanical formula for setting the allowed ROE for a utility, and is the predominant approach in North America. 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. In addition, AAMs do not create any significant regulatory efficiency, as there is still the need to periodically review the base ROE, formula parameters and their weightings. In Mr. Coyne's expert opinion the simple adjustment mechanisms cannot account for other changes that affect a regulated utility's opportunity cost and that historical relationships between equity returns and observable factors such as bond yields may not reflect the changes in the capital markets and investors' expected returns.
>
> **9.1 *THE HISTORY OF AAM FORMULAS***
>
> As described below, AAMs are no longer prevalent. With the exception of the OEB, regulators in Canada have either suspended or eliminated the AAM.
>
> In the 1980s and 1990s, US regulators made two attempts at instituting generic, formula-based approaches to setting the cost of capital (one at the federal level and one in the state of New York). In the end, however, the federal and state jurisdictions retained their longstanding, case-by-case approach over legal concerns that a company-specific record must support the finding of a Fair Return.[95]

58.1 Please explain when the OEB last undertook a cost of capital proceeding.

Response:

Concentric provides the following response:

The OEB last undertook a cost of capital proceeding in 2009 to review the operation of its ROE formula in response to concerns that the formula may not have been producing returns that met the Fair Return Standard due to market conditions during the financial crisis of 2008/2009. The OEB revised its ROE formula in December 2009 to include the spread between government and utility bonds, as well as the change in government bond yields.

58.2 Please provide the OEB's rationale for retaining the Automatic Adjustment Mechanism.

Response:

Concentric provides the following response:

On pages 31-32 of Decision EB-2009-0084, the OEB listed six key principles with respect to its cost of capital policy. These were: 1) meeting the Fair Return Standard; 2) the overall ROE must be determined solely on the basis of a company's cost of equity capital; 3) efficient amount of investment; 4) predictability, transparency, and stability; 5) systematic and empirically based approach; and 6) minimize the time and cost of administering the framework. The OEB retained the ROE formula because the Board determined that it provided regulatory efficiency and, as amended in 2009, was found to work reasonably well in meeting the fair return standard. The Board also indicated that it would periodically review the ROE formula (approximately every 4-5 years) to ensure that it was continuing to produce a reasonable return.

In 2014, OEB Staff commenced a review of the results of the ROE policy since its inception at the end of 2009, including the actual financial results of rate-regulated utilities and the performance of the existing policy in relation to expected outcomes. Staff concluded:

> Based on the results of this review, OEB staff has concluded that the methodology adopted in late 2009 has worked as intended. Movement in the parameters have followed macroeconomic trends and activity, and have not resulted in excessive or anomalous volatility. While there is more volatility observed in the financial performance of utilities, these are largely due to other reasons. (Review of the Cost of Capital for Ontario's Regulated Utilities, OEB Staff Report, January 14, 2016, p. 1).

In recent years, the ROE formula in Ontario has produced lower returns as interest rates on government and utility bonds declined to near historical lows while market risk has increased. Mr. Coyne understands that the OEB is once again re-examining its formula.

59. Reference: Exhibit B1-8, page 57

> The implementation of the formulaic approach in Canada created a persistent divergence between allowed utility returns in Canada and the US[25]. By 2008-2009, the formula approach created such low ROE values that regulators could not ignore the problems with the formula approach any further.

59.1 How were the ROEs determined to be 'low' instead of appropriate?

Response:

As explained in FortisBC's evidence, between 2008 and 2009, multiple Canadian utility regulators from the NEB and the AUC to the Regie and the BCUC moved away from the formula approach. This was because they determined that the return on equity generated under the formulas did not meet the Fair Return Standard.

In reaching that conclusion, regulators took into consideration evidence from the utility analysts, credit rating agencies, utility cost of capital experts and other stakeholders. For instance, the BCUC's 2009 decision to eliminate the formula approach was informed by evidence from the investor community's statements that the formula approach in use by regulators in Canada was becoming confiscatory and did not reflect the real world changes in the cost of capital:

> Mr. Carmichael states that the financial performance of utilities in Canada lags the performance of US based utilities. This has prompted an equity analyst to suggest that ROE formulae in use by regulators in Canada are "confiscatory and fail to meet the fair return standard," while other analysts suggest that the formulae are now "broken." According to the latter group of analysts, under current financial market circumstances such formulas result in lower rates of return on common equity, while all evidence indicates that capital markets require higher returns on corporate securities reflecting the re-pricing of risk which has taken place. Debt analysts have opined that ROE results produced by the formulas "have not reflected the real world increase in the cost of capital" and "the annual ROE adjustment is not even yielding the right direction of change in the cost of capital."
> …
>
> A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.

59.2 Please elaborate on the problems that were caused by the low ROE values, and please provide examples.

Response:

As explained by Drs. Gordon and Makholm in their paper (footnote 95 in the FortisBC's evidence), reverse-engineering the effect of the Canadian generic formula is not a practical and objective possibility to measure the effect it has had on utility equity investments in Canada.

Nevertheless, looking at the cross-border investments can provide some clues. The table below, produced by Concentric, examines the cross-border utility investment that has occurred since 2000. Concentric's research focuses on those transactions involving a U.S. utility acquiring a Canadian utility or a Canadian utility acquiring a U.S. utility and excludes acquisitions of specific assets, such as generation facilities, renewable assets, electric and gas transmission assets. From 2000-2020, Concentric identified 24 transactions where a Canadian utility acquired a U.S. utility and three instances where a U.S. utility acquired a Canadian utility. Table summarizes these M&A transactions since 2000.

Buyer	Target	Deal Value (millions)	Year
Algonquin Power & Utilities	Kentucky Power	$1,625	Pending
ENMAX Corporation	Emera Maine	$959	2019
Algonquin Power & Utilities	St. Lawrence Gas Company, Inc.	$60	2019
AltaGas	WGL Holdings Inc.	$4,544	2018
Algonquin Power & Utilities	St. Lawrence Gas Company Inc	$1,495	2017
Crius Energy Trust	U.S. Gas & Electric Inc.	$6,952	2017
AltaGas	WGL Holdings Inc.	$6,509	2018
Caisse de dépôt et placement	IPALCO Enterprises Inc.	$134	2016
Fortis Inc.	ITC Holdings Corp.	$244	2016
Algonquin Power & Utilities	Empire District Electric Co.	$3	2017
Emera Inc.	TECO Energy Inc.	$2,547	2016
Algonquin Power & Utilities	New Hampshire Gas Corp	$55	2015
Caisse de dépôt et placement	IPALCO Enterprises Inc.	$986	2015
Fortis Inc.	UNS Energy Corp.	$141	2014
Algonquin Power & Utilities	New England Gas Company	$41	2013
Algonquin Power & Utilities	Gas distribution operations	$780	2013

Buyer	Target	Deal Value (millions)	Year
Fortis Inc.	CH Energy Group Inc.	124	2013
AltaGas	SEMCO Holding Corp.	$270	2012
Gaz Métro LP	Central Vermont Public Service	$478	2012
Algonquin Power & Utilities	Gas distribution operations	$76	2012
Algonquin Power & Utilities	California Pacific Electric Co	$189	2012
Algonquin Power & Utilities	Granite State/EnergyNorth	$197	2012
Gaz Métro LP	Green Mountain Power Corp.	$1,625	2007
NS Power Holdings Inc.	Bangor Hydro-Electric Co.	$959	2001
Total		**$30,993**	
U.S. Buyers Acquiring Canadian Utilities Since 2000			
Berkshire Hathaway Inc.	AltaLink LP	$3,240	2014
Investor Consortium	Terasen Water & Utility	$108	2006
Kinder Morgan Inc.	Terasen Inc	$3,398	2005
Total		**$6,746**	

The fact that Canadian companies have been so active in seeking U.S. acquisition targets suggests that Canadian companies see both the opportunity for growth and the potential shareholder returns in the U.S. as being favourable. The correspondingly fewer transactions involving a U.S. utility acquiring a Canadian utility can be explained, in part, by the smaller number of IOUs in Canada that are potential targets for a U.S. company, and the lower allowed returns in Canada in relation to those in the U.S.

Over the long-term, a consistent, unexplained differential between allowed ROEs and equity ratios of Canadian and US companies can further move capital away from Canada to the U.S.

Triggers for Future Applications

60. Reference: Exhibit B1-8, page 62

> **10. TRIGGERS FOR FUTURE APPLICATIONS**
>
> The BCUC's amended scope for Stage 1 of this GCOC proceeding identifies "the criteria, off-ramps or other triggers to warrant a future cost of capital proceeding"[101] as one of the matters in scope that needs to be considered in this proceeding. FortisBC believes, for the reasons set out below, that the BCUC should not establish a trigger in advance. The established approach, which includes periodic review of utilities' cost of capital, is most appropriate.
>
> FortisBC is not aware of any regulator in Canada that uses an automatic trigger mechanism to initiate cost of capital review nor is able to formulate a trigger mechanism that can capture all of the various factors that can impact the investors' opportunity cost.
>
> As explained in Mr. Coyne's evidence, off-ramps are often used in incentive rate-setting plans to trigger a review of the plan in the event that the company's actual earned ROE is below or above a specified level and indeed similar off-ramp mechanisms already exist in FEI's and FBC's Multi-year Rate Plans. Cost of capital proceedings, however, are focused on estimating the "opportunity cost" and there is no basis to rely on the variance between realized and allowed ROEs to initiate a cost of capital proceeding since this variance does not necessarily reflect the changes in investors' opportunity cost nor the changes in market conditions. Numerous business and capital market factors affect the cost of capital for utilities and these factors are inherently dynamic. In Mr. Coyne's expert opinion, there is no need to change the current approach of conducting periodic cost of capital reviews and that periodic cost of capital proceeding that is conducted every three to five years is the best approach to ensure that the authorized return remains appropriate for regulated utilities, including those in BC.[102]

60.1 Please explain whether or not Mr. Coyne's evidence assumes a relatively stable investment environment.

Response:

Concentric provides the following response:

As discussed throughout Mr. Coyne's report, the financial models he has used to estimate the cost of equity for FEI and FBC (DCF, CAPM, Risk Premium) use both current and projected market data. Mr. Coyne explains in his report that interest rates on government bonds are projected to increase from current low levels as monetary policy in both Canada and the U.S. becomes more neutral in response to higher inflation and lower unemployment. Mr. Coyne would not characterize current market conditions as being relatively stable.

60.2 Could a sudden and serious change in the global or local geopolitical environment affect investments to the extent that a review should be triggered? Please explain why or why not.

60.2.1 If yes, please provide examples of when a review might be triggered beyond a standard 3 or 5 years.

Response:

Concentric provides the following response:

It is possible that a sudden or serious change in the global or local geopolitical environment could affect investments to the extent that a review should be triggered. However, such events are often short in duration, and may not affect the long-term cost of capital. As always, market data on changes in government and utility bond yields, the GDP forecast, the inflation outlook, EPS growth rates and utility share prices would be the best indicators as to how such events were affecting the results of the models commonly used to estimate the cost of equity and whether that should trigger a review of the cost of capital. For example, in 2009 the OEB determined that its formula was not producing a return that met the Fair Return Standard due to changes in economic and capital market conditions during the financial crisis of 2008/2009.

60.3 What circumstances, if any, might suggest to the Commission that the ROEs are set either too high or too low.

Response:

Concentric provides the following response:

Among the factors that the Commission might consider in assessing whether the authorized ROE is too high or too low are: 1) whether the return is comparable to those investors can earn on similar risk utilities in other jurisdictions, 2) whether the utility is able to maintain its credit rating and financial integrity, 3) whether the utility is able to attract capital on reasonable terms, and 4) the implied risk premium over the risk-free rate.

Attachment 23.2

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 25.1

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Attachment 29.3

REFER TO LIVE SPREADSHEET MODEL

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Attachment 36.2

Diane Roy
Vice President, Regulatory Affairs

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August 12, 2020

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Energy Inc. (FEI)

Biomethane Energy Recovery Charge (BERC) Rate Methodology

British Columbia Utilities Commission (BCUC) Decision and Order G-133-16 Compliance Filing – BERC Rate Assessment Report

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On August 12, 2016, the BCUC issued its Decision and Order G-133-16 on FEI's 2015 BERC Rate Methodology Application approving. Directive 16 of the Decision directed FEI as follows:

> FEI is directed to file a comprehensive assessment report for Commission approval at the earlier of the application by FEI for a transfer of biomethane inventory from the BVA to the MCRA or four years after the date of issue of this decision, whichever comes first.

FEI respectfully submits the attached BERC Rate Assessment Report in accordance with the Decision.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

BCUC File 53700
Batch 50942

FORTIS BC™

FORTISBC ENERGY INC.

Biomethane Energy Recovery Charge Rate Methodology

Comprehensive Assessment Report

In Compliance with British Columbia Utilities Commission Order G-133-16

August 12, 2020

Table of Contents

List of Appendices

1. SUMMARY OF REPORTING REQUIREMENTS

On August 12, 2016, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-133-16 (Decision) on FortisBC Energy Inc.'s (FEI or the Company) 2015 Biomethane[1] Energy Recovery Charge (BERC) Rate Methodology Application (Application). In the Decision, the Panel approved, among other things, changes to the BERC rate methodology, a Short Term BERC Rate and a Long Term BERC Rate. The Decision also directed FEI to file a comprehensive assessment report (Assessment Report) for BCUC approval at the earlier of: an application by FEI for a transfer of biomethane inventory from the Biomethane Variance Account (BVA) to the Midstream Cost Reconciliation Account (MCRA), or four years after the date of the Decision, whichever comes first[2]. Since FEI has not had a transfer of biomethane inventory from the BVA to the MCRA since the Decision was issued, this Assessment Report is being filed four years from the date of the Decision as directed.

Table 1 below provides a summary of the reporting requirements of Order G-133-16 and where in this Assessment Report the information is presented.

Table 1: Decision Compliance Reporting Requirements

Compliance Reporting Requirement – Directive 16, p. 51	Report Section #
FEI is directed to file a comprehensive assessment report for Commission approval at the earlier of the application by FEI for a transfer of biomethane inventory from the BVA to the MCRA or four years after the date of issue of this decision, whichever comes first (Assessment Report). In the event FEI commits all available supply through the Long Term Contract offering prior to the earlier of these two events, FEI is directed to file the Assessment Report at that time. In the Assessment Report FEI is to include, among any other information FEI views necessary to inform the Commission, the following:	
1. An assessment of the degree to which the new BERC rate methodology has achieved the objective of maximizing revenues.	Section 2
2. An evaluation of the supply/demand balance for the RNG program including an update on the biomethane supply contracted to date and projected to be contracted over the near future.	Section 3
3. For January 1st of each year for the period from the date of implementation of the new BERC rate methodology to date: 3.1. The BVA balance; 3.2. The Short Term BERC Rate; 3.3. The Long Term BERC Rate; 3.4. The CCRC; 3.5. The carbon tax; and 3.6. The costs transferred to from the BVA to the BVA balance Transfer rate base deferral account.	Section 4

[1] Biomethane is also referred to as Renewable Natural Gas (RNG) and the current RNG Program was referred to as the Biomethane Program. Biomethane and RNG are used interchangeably throughout the Application.

[2] Decision, p 51.

Compliance Reporting Requirement – Directive 16, p. 51	Report Section #
4. Monthly data for the following for the period from the date of implementation of the new BERC rate methodology to date : 4.1. Number of customers by rate class and by offering (i.e. short-term versus long-term); 4.2. Churn rate by customer class; and 4.3. RNG sales quantities and revenues by rate class and by offering.	Section 5
5. For long-term contracts, provide a summary of the terms and conditions that have been included in executed contracts to date.	Section 6
6. In the case where the Assessment Report is triggered by an application to transfer biomethane quantities from the BVA to the MCRA, a discussion of the steps FEI has taken to realize the value of the environmental attributes by other means than through sales to voluntary customers.	N/A
7. An analysis of customer awareness and education spending for each year over the period from the date of implementation of the new BERC rate methodology to date including analysis against any metrics that are established by FEI as referred to in section 4.5.	Section 7
8. An evaluation of the effectiveness of the customer awareness and education spend over the period from the date of implementation of the new BERC rate methodology to date.	Section 7
9. Recommendations regarding the need for any changes to the BERC rate methodology.	Section 8

2. BERC RATE METHODOLOGY

In 2015, FEI observed a negative trend in customer enrolment for the RNG Program. The negative trend in enrolments was believed to be due to the premium customers were required to pay for RNG as compared to conventional natural gas. FEI's success in enrolling customers up to that point in the RNG Program showed that customers would voluntarily pay a premium for RNG to reduce their greenhouse gas (GHG) emissions. However, in 2015, the BERC Rate, and the associated premium as compared to conventional natural gas, had reached a point that discouraged customers from voluntarily enrolling in the RNG Program.

This trend could have resulted in a negative impact to non-RNG customers as greater unsold biomethane and, therefore, greater unrecovered costs, would have to be transferred to the MCRA account. To avoid this potential outcome, FEI proposed that the BERC Rate be set to a level that would encourage more participation in the RNG Program, stimulate increased demand for RNG, increase overall revenues from the RNG Program, and reduce the impact to natural gas delivery and commodity rates.

The BERC Rate is the rate FEI charges for biomethane purchased on a voluntary basis by customers enrolled in the RNG Program. In the 2015 Application, FEI proposed a floating BERC Rate based upon a fixed premium on conventional natural gas, and a lower priced option for customers willing to enter into long-term agreements with FEI that met certain volume and

term commitments. The Decision approved the two options proposed by FEI: the Short Term BERC Rate and the Long Term BERC Rate. The Short Term BERC Rate is equal to the BCUC approved January 1st Commodity Cost Recovery Charge (CCRA Rate) each year, plus the approved Carbon Tax rate, plus a premium of $7.00 per gigajoule (GJ). The Long Term BERC Rate is set at a $1.00 discount to the Short-Term BERC Rate to reflect the benefits to FEI and its non-RNG customers, including long-term revenue certainty, a more predictable load throughout the year, and reduced marketing efforts required to reach this customer group.

FEI stated that the BERC rate methodology proposed in the 2015 Application (and ultimately approved in the Decision) would reduce the risk to non-RNG customers of the cost of unsold biomethane volumes. The concept was to sell most or all of the available RNG supply at a lower price instead of selling less volume at a higher price. This higher volume at a lower price approach was proposed to help avoid the transfer of a greater amount of unsold RNG to the MCRA and thus the potential for transferring all the costs associated with any such unsold RNG volumes to non-RNG customers.

In the Decision, the BCUC Panel identified three overarching objectives which guided its decision approving the BERC rate methodology, as follows:

1. **Maximize the recovery of program costs from RNG customers.** This objective was laid out in the previous Commission decision. In order to maximize the recovery of program costs, it may not be sufficient to maximize the number of RNG customers, reduce the number of net RNG customer drops or to maximize the volume of RNG sold. The revenue received from biomethane customers must be maximized. This is an important distinction, as there has been discussion in this proceeding of all of these metrics. When considering an appropriate BERC price setting mechanism, the Panel will consider whether the proposed pricing mechanism is expected to maximize revenues. If it isn't possible to make a determination about maximizing revenues, the Panel will then consider whether the proposed pricing mechanism is expected to at least increase revenues relative to what revenues are expected to be in the absence of a change in the BERC pricing methodology.
2. **Manage biomethane inventory.** FEI expressed concern that the longer the inventory ages, the more difficult it may be to sell. To the extent this is an issue, an exception to the principle of maximizing revenue may be required, and instead a BERC that maximizes sales volume may be more appropriate. However, as FEI points out, it also needs to ensure that sufficient inventory is available in the event a large long term customer signs up. Inventory aging issues will be addressed in section 4.3 of this Decision.
3. **Establish a BERC rate setting mechanism that is robust, effective and provides regulatory efficiency.** The cost of proceedings to set the BERC rate can add considerably to the cost of biomethane. A pricing mechanism that requires a minimum of regulatory oversight will minimize those cost impacts. The current mechanism, based on biomethane acquisition costs, with a relatively simple annual adjustment, is an

> example of such a mechanism. A market rate that floats with the Conventional Gas Cost is another such example. A fixed price, for example, which could require substantial and frequent revisits to consider the effect of inflation, changing commodity prices, changing costs of acquisition may not be as efficient.[3]

In the Decision, FEI was directed to file a comprehensive report to assess the degree to which the revised BERC rate methodology has achieved the objective to maximize RNG program revenue. FEI provides the following evaluation of the Short Term BERC Rate and Long Term BERC Rate, which demonstrates that the revised BERC rate methodology has resulted in increased program participation, increased RNG sales volumes and increased program revenues received from RNG customers. Given these increases, FEI's assessment is that the revised BERC rate has been successful and has resulted in greater revenues that would have been the case under the previous BERC rate methodology.

2.1 *ASSESSMENT OF THE REVISED BERC RATE METHODOLOGY*

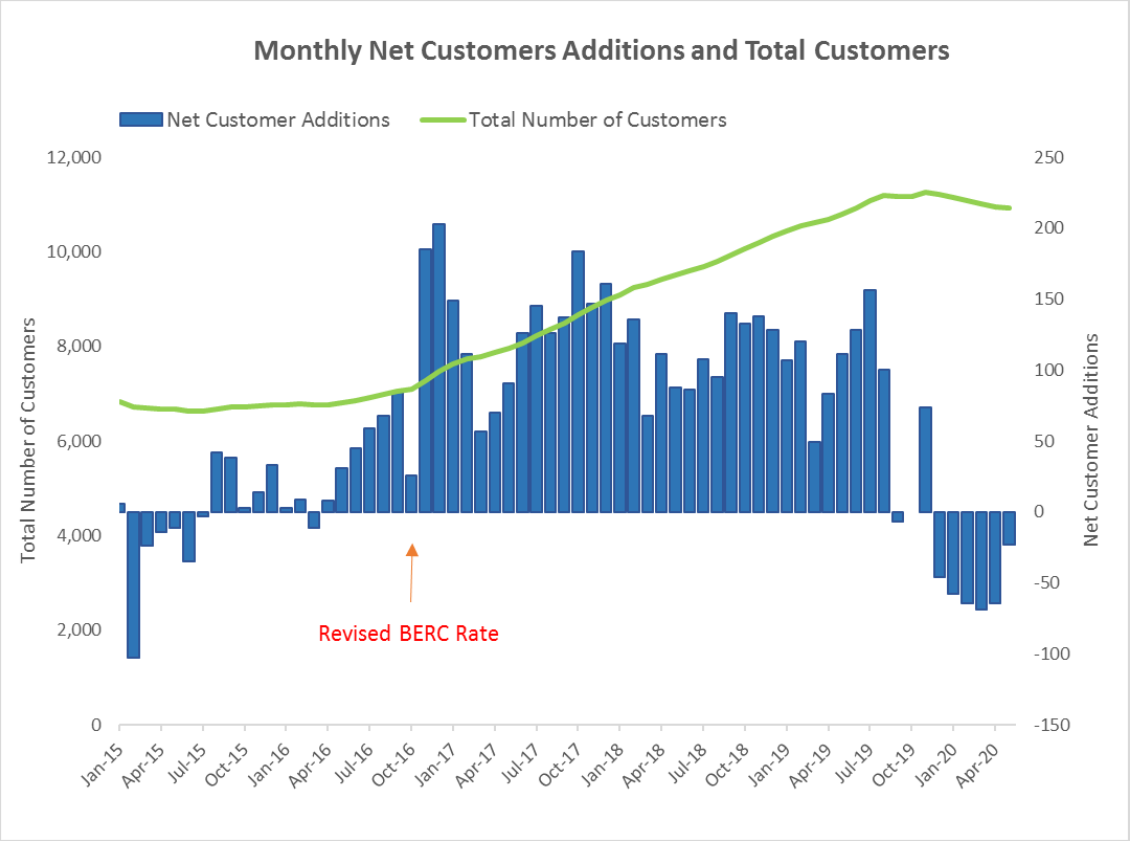
2.1.1 Customer Participation

The revised BERC rate methodology has been successful in driving a steady increase in voluntary customer participation since its implementation. In 2015, prior to the implementation of the revised BERC rate, customer enrolment rates for the RNG Program were declining and in 2016 they were relatively flat.

Following the Decision, FEI implemented the updated Short Term BERC Rate on October 1, 2016 at $10.209 per GJ. Since the implementation of the Short Term BERC rate, FEI has seen an increase in the rate of customer additions to the RNG Program and a steady increase in overall customer enrolment, as seen in Figure 1 below for the period of October 2016 to the end of 2019. Through this period, the total number of participants increased by 58 percent from approximately 7,100 at the start of the revised BERC Rate to 11,200 by the end of 2019 (demonstrated by the solid green line in Figure 1). The vast majority of this growth in customer enrolments was attributable to residential customers enrolling in Rate Schedule 1B.

[3] Decision, p. 17.

Figure 1: Monthly Net Customers Addition and Cumulative Total Customers



The reduction in customer additions towards the end of 2019, as shown in Figure 1 above, was due to a temporary closure of the Biomethane Program to new participants as RNG supply was oversubscribed. This situation was due to a number of factors, including increased enrolment of residential and small commercial customers, increased enrolment and volume from large long-term contract customers, and variability in the expected timing and volume of RNG delivered from new supply projects during this time.[4] The temporary closure of the RNG Program led to the steady erosion of the total number of customers enrolled, due to the ordinary level of customers exiting the program not being replaced by new participants. FEI expects that new RNG supply projects will begin delivering significant additional volumes of RNG beginning in late 2021, at which time FEI will again be actively engaged in enrolling new customers.

The market's acceptance of the revised BERC rate methodology is also demonstrated in Figure 2 below.

[4] An example is the approved City of Surrey Biofuel Facility, which was delayed in-service by over a year, and took longer than anticipated to deliver expected volumes of RNG.

Figure 2: Monthly Net Customers Addition and Short Term BERC Rate

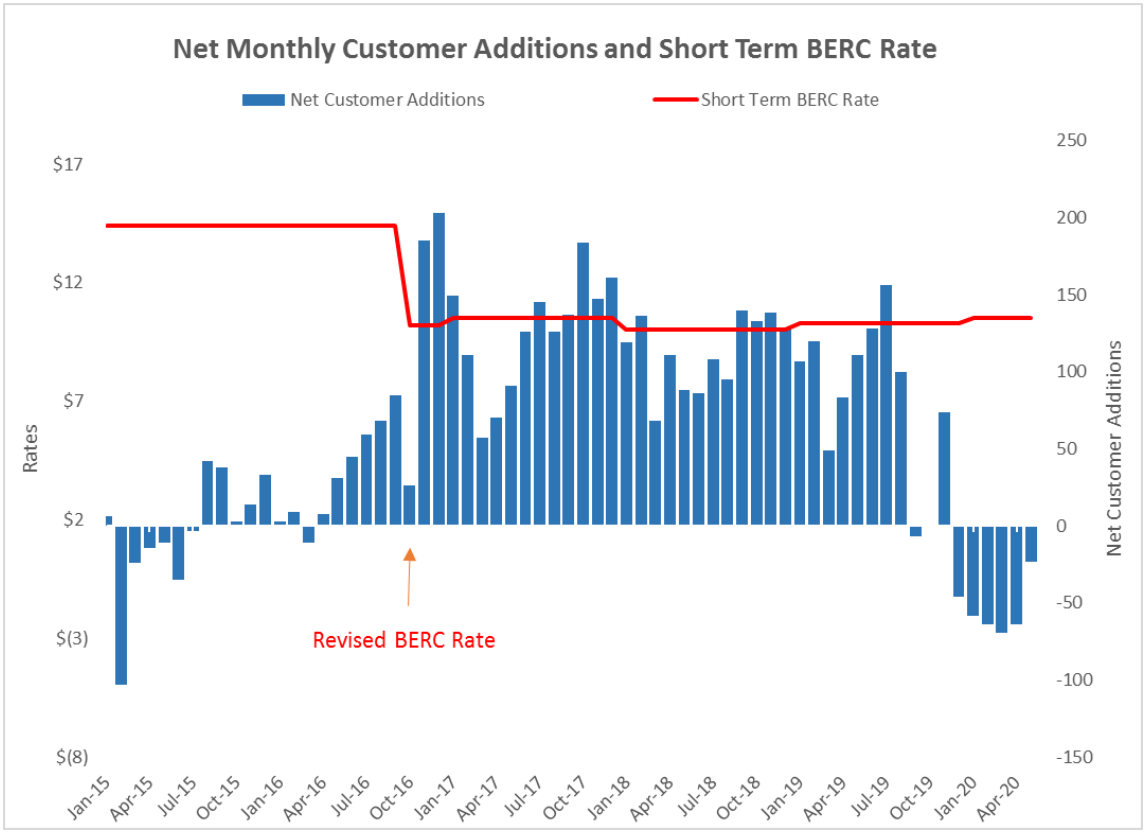


Figure 2 shows that customers reacted positively to the revised BERC rate methodology, by the increased customer additions to the program since the price paid by customers for RNG was reduced. Moreover, the increased rate of customer additions has been maintained since the revised BERC rate was introduced.

The Long Term BERC Rate has also been successful in generating participation in the RNG Program. Following the Decision, FEI implemented the Long Term BERC Rate on October 1, 2016, at the approved $1 discount from the $10.209 per GJ Short Term BERC Rate in place at that time, with a minimum floor price of $10 per GJ. Since the implementation of the revised BERC rate methodology, the Long Term BERC Rate has remained at the $10 per GJ floor price. While the Long Term BERC Rate of $10 per GJ has not to date offered customers a significant price discount to the Short Term BERC Rate, the long term contracts have been well received. More sophisticated, larger volume customers have shown a preference for securing access to RNG with a 5 or 10 year contract than the standard Rate 11B sales agreement of up to 1 year in length. FEI understands that the long term contracts make it easier for these customers to choose RNG to meet their GHG emission reduction objectives since the contract provides them with RNG supply security. To date, FEI has executed three long term contracts, and has been approached by additional customers interested in signing long term contracts. FEI's ability to enrol additional customers in long term contracts has been hindered by the delay in acquiring additional RNG supply volumes.

The demand for long term access to large volumes of RNG is also driven by factors that are specific to particular industries or customers. These drivers include GHG emissions reduction targets, the price of long term RNG compared to alternatives, and environmental initiatives from different levels of government. For example, among municipalities, the demand for RNG appears to be driven the municipality's climate action policy and GHG reduction targets. Achieving these policies and targets may be most cost effective, both in terms of capital investment and on-going operating costs, by using RNG for their municipal-owned buildings that have gas equipment. A significant driver of RNG demand in the education sector, including UBC, is the provincial government's GHG emissions reduction targets, while RNG demand in the transportation sector appears to be driven by BC's Low Carbon Fuel Standard (BCLCFS).

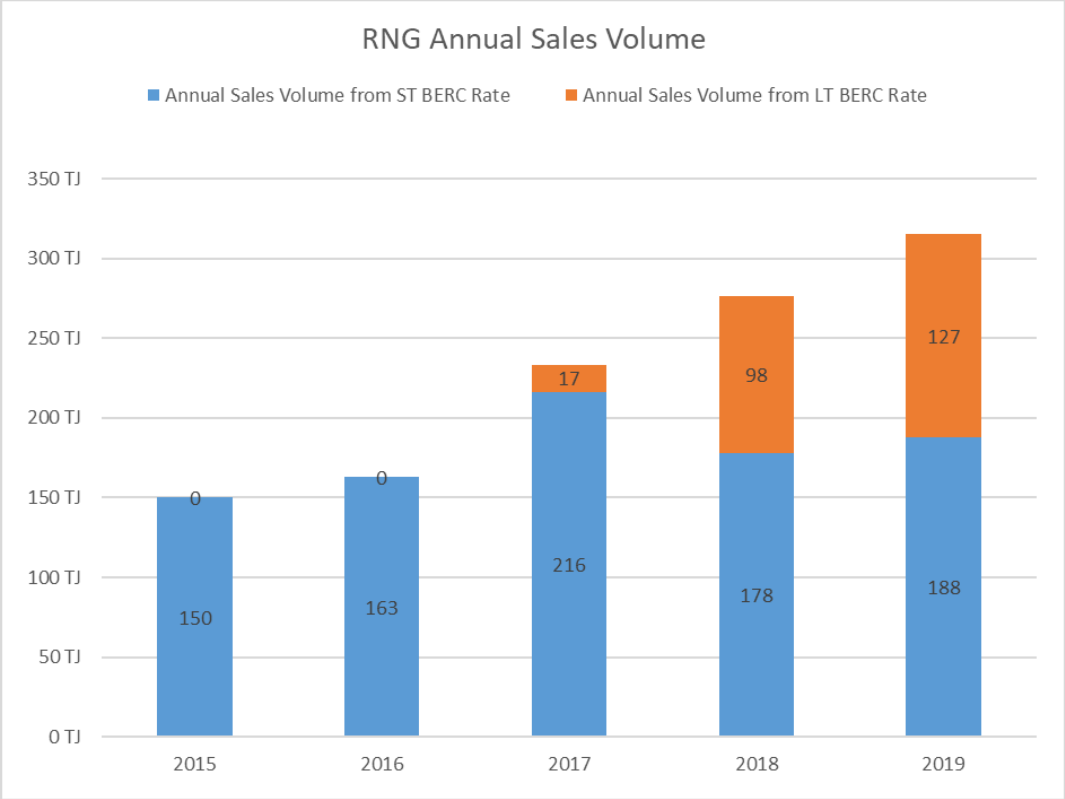
These additional drivers have primarily affected large volume RNG customers and have not impacted the mass market residential and small commercial customers. FEI continues to monitor these drivers of demand for large volumes of RNG and may propose RNG Program modifications in the future if required to ensure the long term balance of supply and demand.

2.1.2 Sales Volume

As can be seen in Figure 3 below, there has been an increase in the volume of RNG sold since the revision to the BERC Rate. The blue bars in Figure 3 demonstrate that the annual RNG sales volume from Short Term BERC Rate customers has grown substantially since 2015, the last full year of operation under the previous BERC rate methodology. From the end of 2016, when the revised BERC rate methodology was implemented, to the end of 2019, the sales volume for Short Term BERC Rate customers[5] increased from approximately 163 Terajoules (TJs), to approximately 188 TJs, which is a growth of 15 percent over the three-year period, or an average annual growth rate of nearly 5 percent.

[5] Short Term BERC Rate customers include customers enrolled in Rate 1B, Rate 2B, Rate 3B Rate 5B, and Rate 11B.

Figure 3: RNG Annual Sales Volume



The increase short-term sales volumes in 2017, and the subsequent decrease in 2018, as shown in the blue bars in the figure above, is due to the migration of UBC and City of Vancouver from the Short Term BERC Rate to the Long Term BERC Rate in 2017 and 2018. The short term volumes sold in 2017 increased compared to 2016 when the City of Vancouver began consuming a significant volume of RNG. The Short Term BERC Rate sales volume then declined in 2018, as both UBC and the City of Vancouver executed long term contracts and migrated to the Long Term BERC Rate. The impact of this migration also increased the long-term sales volumes from 2017 to 2018, as shown in the orange bars in the figure above. The long term sales volume increased again in 2019 due to Translink starting service on February 1, 2019.

The average volume of RNG sold per residential customer over the period has seen a modest increase since the revised Short Term BERC Rate was introduced. At the end of 2016, RNG sales volumes were approximately 60,500 GJs for approximately 6,968 residential customers[6], for an average volume per customer of approximately 8.7 GJs. By the end of 2017, the average volume per customer had increased to approximately 10.9 GJs and has remained above 10 GJ per customer since. This average volume of 10 GJs per year represents approximately 11 percent of the annual demand of an average FEI residential customer, indicating that a blend of

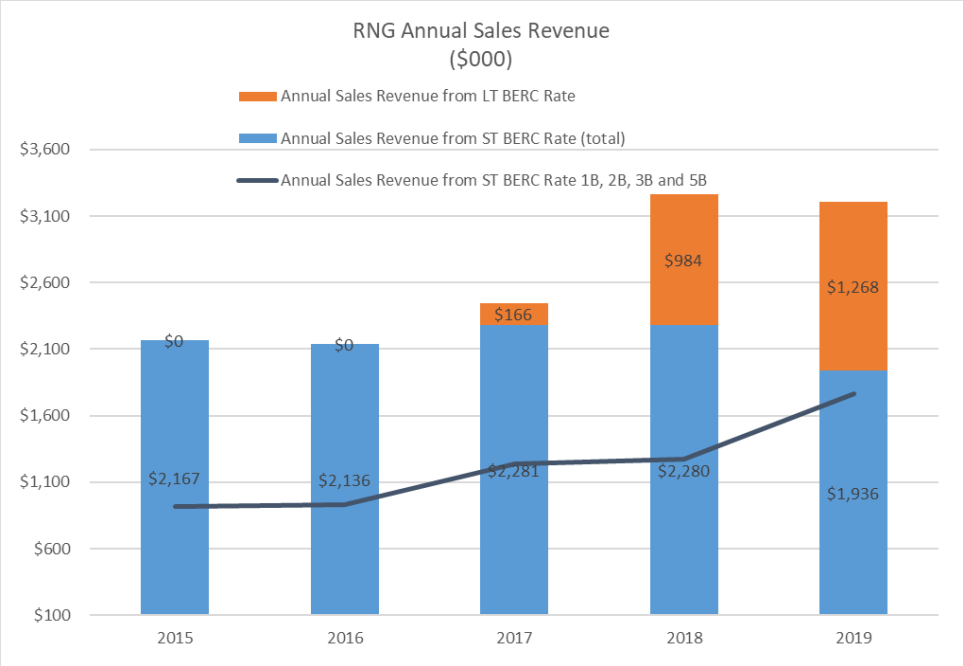
[6] The number of residential customers is taken as the simple average of the number enrolled in January and December of the year.

approximately 10 percent remains a good indicator of the market's desired proportion of RNG to natural gas.

2.1.3 Total Revenues

Figure 4 below shows the annual revenue from both Short Term BERC Rate and Long Term BERC Rate customers which demonstrates that total revenues have increased since implementation of the revised BERC rate methodology.

Figure 4: Annual RNG Revenue by Short Term and Long Term Customers



The annual RNG revenue from Short Term BERC Rate customers increases and then decreases over the period, as shown by the blue bars in Figure 4. This was due to the migration of UBC and the City of Vancouver from the Short Term BERC Rate under RS 11B to the Long Term BERC Rate as discussed above.

As shown in the black line in Figure 4 above, the total revenues generated from mass market residential and commercial customers (RS 1B, 2B, 3B and 5B) grew over the period as sales volumes and customer participation steadily increased. Further, although the price per GJ of RNG declined under the revised BERC rate, the average revenue generated per residential customer was approximately $110 per customer in 2016 and remained the same by the end of 2019. This indicates that the new Short Term BERC rate has not reduced the per customer revenues for the majority of customers. When coupled with the increased number of customers enrolled, the effect is increased revenues.

The revenue generated from Long Term BERC Rate contracts also increased over the period, as demonstrated by the orange bars in Figure 4, from nil at the introduction of the Long Term BERC Rate to nearly $1.3 million by the end of 2019.

2.2 *CONCLUSION*

The evidence supports the conclusion that the revised BERC rate methodology has enhanced revenue and the recovery of RNG Program costs from RNG customers. FEI has seen growth in customer enrolments, volumes sold and revenues collected since the implementation of the revised BERC rate methodology, thereby avoiding the need to transfer some RNG Program costs to non-RNG customers that would otherwise have been triggered by unsold RNG volumes.

Presently the RNG Program is fully subscribed, meaning that all RNG supply volumes purchased by FEI are being sold to RNG customers. This is partially due to the revised BERC rate methodology contributing to increasing demand from customers, but also because RNG supplies did not materialize as originally forecast. As discussed further in Section 3 below, FEI is expecting to see significant growth of RNG supply becoming available in late 2021.

At this time, FEI believes that the revised BERC rate methodology as approved in the Decision remains appropriate as it contributes to ensuring that the demand for RNG remains strong and will support new RNG supply volumes as they become available. FEI will continue to monitor the market and RNG Program as new supply becomes available and as drivers of demand in the market evolve, such as government policy. Given the current state of supply and demand, FEI is satisfied that the BERC rate methodology in place remains appropriate and believes that a review or changes are not necessary at this time.

3. SUPPLY/DEMAND BALANCING FOR THE RNG PROGRAM

The demand for RNG currently exceeds the available supply from FEI's suppliers. In 2019, as demand was exceeding the available supply, FEI ceased accepting new enrolments in the RNG Program and curtailed the volume of RNG available for sale to large volume, interruptible RNG rate customers under Long Term BERC Rate contracts served through Rate Schedule (RS) 11B. In 2019, the total volume of RNG sold to meet customer demand was 315 TJs. The total RNG supply from existing RNG production facilities was 225 TJs. This represents a 28 percent increase in RNG supply over the 2018 total of 176 TJs. The shortfall of 90 TJs between RNG supply versus RNG sold was fulfilled with the purchase of carbon offsets.

The temporary closure of the RNG Program to new participants and the curtailment of volumes under RS 11B are likely to be maintained until late 2021. FEI forecasts that in the later part 2021 the available supply of RNG will increase significantly and will exceed the demand of all customers currently enrolled in the RNG Program. This increase in supply is due to the progress FEI has made in growing the RNG supply portfolio over the past year. Table 2

presents the new supply projects FEI expects to be completed over the three year period from 2020 through 2022. This table includes supply projects contracted to date.

Table 2: Contracted RNG Supply Projects

	1	2	3	4
	Project	**Contract Status**	**BCUC Approval Status**	**Anticipated Start Date (Month-Year)**
Existing	Fraser Valley Biogass	Contacted	Approved	N/A
	Seabreeze Farms	Contacted	Approved	N/A
	Kelowna Landfill	Contacted	Approved	N/A
	Columbia Shushwap Regional Dist.	Contacted	Approved	N/A
	City of Surrey	Contacted	Approved	N/A
			Contract Max Annual Volume (TJ/Yr)	**529**
			Expected Annual Volume (TJ/Yr)	**310**
			Proportion of Total Expected Volume	**5.3%**
Future	Tidal Stormfisher	Contracted	Approved	Aug-20
	Project #1	Contracted	In Progress	Sep-20
	Lulu Island Waste Water	Contracted	Approved	Dec-20
	Faromor	Contracted	Approved	Jan-21
	Dicklands Farm	Contracted	Approved	Sep-21
	Lethbridge Biogas	Contracted	Approved	Sep-21
	Bradam Hamilton	Contracted	Approved	Sep-21
	Tidal Niagara	Contracted	Approved	Dec-21
	City of Vancouver	Contracted	Approved	Dec-21
	Project #2	Contracted	In Progress	Dec-21
	Bradam Napanee	Contracted	Approved	Jan-22
	Matter	Contracted	Approved	Mar-22
	REN Energy	Contracted	Approved	Jul-22
	GSE	Contracted	Approved	Dec-22
			Contract Maximum Annual Volume (TJ/Yr)	**7,307**
			Expected Annual Volume (TJ/Yr)	**5,493**
			Proportion of Total Expected Volume	**94.7%**
			Grand Total Maximum Annual Volume (TJ/Yr)	***7,836***
			Grand Total Expected Annual Volume (TJ/Yr)	***5,803***

Table 2 shows the maximum contracted volume for each project as well as the expected annual volume. The expected volumes indicated in the table take into account FEI's experience that, on average, new RNG supply projects typically take time to ramp up their production to the maximum RNG volumes.

The current maximum amount of RNG that FEI can contract and remain within the existing Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) is approximately 8,900 TJs per year FEI further anticipates that it will enter into additional biomethane supply agreements before the end of 2020, such that the total maximum supply under executed agreements could reach maximum volume currently set in the GGRR.

As shown by the Grand Total Expected Volume at the bottom of Table 2, when all of FEIs supply projects are completed and supplying RNG, FEI's expected annual supply volume is approximately 5,800 TJs per year. For newly completed supply projects, there can be a ramp-up period before the full expected annual volumes of RNG can be delivered. Table 3 below shows the expected total RNG supply volumes for the years 2020 through 2024, taking this ramp up time and the timing of the new supply volumes, into account. This table includes supply from all of FEI's existing suppliers, as well as all new suppliers expected to be providing RNG between the present time and the end of 2022 as shown in Table 2.

Table 3: Total Expect RNG supply volumes 2020-2024

1	2
Year	**Expected Total RNG Supply (TJ)**
2020	290
2021	950
2022	3,850
2023	5,120
2024	5,580

Figure 5 below provides a visual representation of the monthly forecast of supply versus the monthly forecast of demand from FEI's currently enrolled RNG customers to the end of 2022. In this figure, the sum of the area under the total monthly supply line between the start of January and the end of December 2022 is equivalent to the 3,850 TJ shown in Table 3 above. Figure 5 demonstrates how the supply of RNG, including all current and expected future suppliers, will outgrow the current demand from existing customers, leading to an excess supply which will allow FEI to add new customers to the RNG Program. The total monthly supply includes RNG volumes from all new projects listed in Table 2, which also takes into account a ramp up period in production. The total monthly demand shows the un-curtailed contracted volumes of FEI's current RS 11B Long Term BERC Rate customers as well the forecasted demand from all other currently enrolled customers, but does not include any incremental demand from potential new customer enrolments under any RNG rate schedule. As discussed below, FEI has additional customers interested in entering Long Term BERC Rate contracts once additional supply is available.

Figure 5: Monthly RNG Supply and Demand 2020-2022

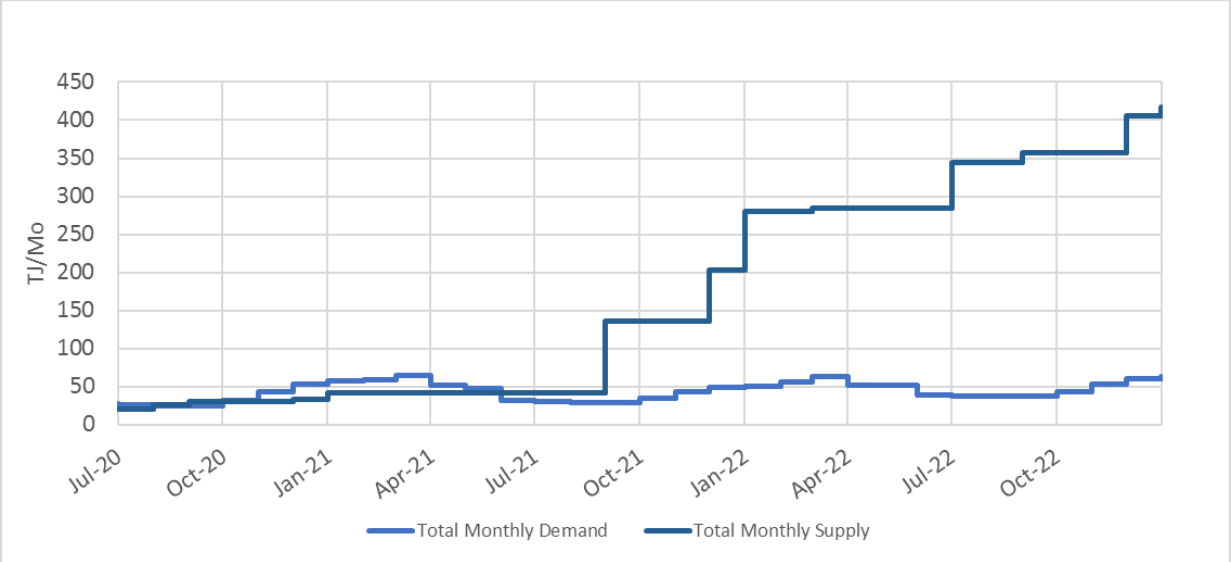


Figure 5 shows how, beginning in September of 2021, the available supply will grow beyond the demand from FEIs currently enrolled customers. In 2022, FEI expects the demand from currently enrolled customers to be approximately 580 TJs for the year, while the volume of supply is expected to exceed 3,800 TJs, or nearly seven times the volume of demand. This excess supply represents the volumes available to serve new customers.

Although FEI has not permitted new participants to enrol in the RNG Program since 2019, a number of large volume customers have made their interest in RNG known to FEI. FEI is currently aware of up to 4 PJs of potential incremental demand for RNG from such customers. The revised BERC Rate has been successful in increasing customer enrolment, sales volume and revenue. FEI believes that maintaining the current BERC rate methodology will be essential to maintaining the interest of new customers enrolling in the RNG Program in 2021 and increasing demand for this new RNG supply.

4. BVA BALANCE, BERC RATES, CCRA RATE, AND CARBON TAX FOR THE PERIOD JANUARY 1, 2016 TO JANUARY 1, 2020

4.1 *BVA BALANCE*

The following tables present the BVA balances for January 1 of each year from the date of implementation of the revised BERC rate methodology to date. The January 1 balance represents the value of RNG inventory at the start of each year, valued at the Short Term BERC Rate in effect at that time. In 2017 FEI sold more RNG than it had avilable, while there was a timing difference with its purchase of carbon offsets in 2018, which resulted in the negative opening value for January 1, 2018.

Table 4: BVA Balance

Item	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20
The BVA balance ($000)	$ 341.0	$ (471.0)	-	$ 1.5

4.2 *SHORT TERM AND LONG TERM BERC RATE*

Following the Decision, FEI implemented the revised BERC rate methodology, resulting in a Short Term BERC Rate on October 1, 2016 of $10.209 per GJ. On January 1 of the following years, the Short Term BERC rate was changed to reflect the change in the CCRA Rate and the Carbon Tax rate. The Long term BERC Rate is based on the higher of the $1 discounted rate from the Short Term BERC Rate, or the $10 per GJ floor rate. The Long Term BERC Rate has been set at $10 per GJ since implementation of the Decision, which is the approved floor rate.

The following tables present the Short Term BERC Rate and Long Term BERC Rate for January 1 of each year from the date of implementation of the revised BERC rate methodology to date.

Table 5: Short Term and Long Term BERC Rates

Item	1-Oct-16	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20
The Short Term BERC Rate	$10.209	$ 10.540	$ 10.039	$ 10.287	$ 10.535
The Long Term BERC Rate	$ 10.000	$ 10.000	$ 10.000	$ 10.000	$ 10.000

4.3 *CCRA RATE*

The following tables present the CCRA Rate for January 1 of each year from the date of implementation of the new BERC rate methodology to date.

Table 6: CCRA Rates

Item	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20
The CCRC	$ 2.050	$ 1.549	$ 1.549	$ 1.549

4.4 *CARBON TAX*

The following tables present the Carbon Tax rate[7] for January 1 of each year from the date of implementation of the new BERC rate methodology to date.

[7] Carbon tax was $1.4898 since July 1, 2012, increased to $1.7381 on April 1, 2018, and increased to 1.9864 on April 1, 2019.

Table 7: Carbon Tax Rates

Item	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20
The Carbon Tax	$ 1.4898	$ 1.4898	$ 1.7381	$ 1.986

4.5 *BVA BALANCE TRANSFER RATE BASE DEFERRAL ACCOUNT*

The following tables present the costs transferred from the BVA to the BVA Balance Transfer rate base deferral account, as of January 1 of each year from the date of implementation of the new BERC rate methodology to date.

Table 8: BVA Balance Transfer

Item	1-Jan-17	1-Jan-18	1-Jan-19	1-Jan-20
The costs transferred from the BVA to the BVA balance Transfer rate base deferral account ($000)	2,977.0	2,522.0	3,701.8	2,625.6

5. MONTHLY CUSTOMER DATA FOR THE PERIOD JANUARY 1, 2016 TO JANUARY 1, 2020

As shown in section 2 above, FEI has seen steady growth in net customer additions since the implementation of the revised BERC rate in October 2016.

Appendix A presents the monthly data for the period from the date of implementation of the revised BERC rate methodology Decision to date. The tables in Appendix A show the number of customers by rate classes and offering (i.e., Short Term BERC Rate versus Long Term BERC Rate), churn rate[8] by customer class, RNG sales quantities by rate class and by offering, and RNG sales revenue by rate classes and by offering.

6. LONG-TERM CONTRACTS SUMMARY OF TERMS AND CONDITIONS

In the Decision, FEI was directed to provide a summary of the terms and conditions that have been included in executed contracts to date. FEI has signed three Long Term BERC Rate agreements which have been filed with the BCUC as Tariff Supplements under RS 11B. These three agreements are with UBC, City of Vancouver and Translink, are approved by the BCUC in Orders G-64-18, G-212-18, and G-19-19 and filed with the BCUC under Tariff Supplements K-1,

[8] Churn Rate is calculated using the number of customer drop off in the month dived by the average number of customers in the month.

K-2, and K-3 respectively. The tables in Appendix B summarize the contract terms and conditions for each of the executed agreements.

7. CUSTOMER AWARENESS AND EDUCATION

FEI believes that customer knowledge and awareness levels about the RNG Program have increased during the period from 2016 to 2019, which has contributed to the increased program participation over that period. During 2016 to 2019, customer awareness expenditures focused on customer research, mass market campaigns targeted towards the residential customer segment, along with education to municipalities and commercial customers. In 2018, as it became apparent that demand would exceed supply, customer awareness expenditures for the RNG Program were scaled back.

In 2016, FEI contracted a customer research company to garner a better understanding of customer perceptions and knowledge of RNG. The findings from the customer research study indicated low familiarity of the RNG Program among FEI customers in that only 6 percent were "very familiar" with FEI's RNG Program. Barriers to program participation were also identified that included price, a lack of understanding of the RNG Program, scepticism around the environmental benefits of RNG, questions about safety, lack of knowledge of how RNG is sourced, along with how existing gas appliances in the home could function with RNG. In addition, the research identified certain customer segments that had a higher potential for program participation. The customer research study provided insights into the development of new customer outreach and awareness campaigns and delivery of those campaigns through different media channels. This new campaign was developed and launched into market in 2017 over various online channels, included behaviourally-targeted display banners, pre-roll video, social media, and out of home channels, including radio spots and Skytrain platform posters.

In 2017, based on the research results, a redesigned customer awareness campaign launched which encouraged the audience to learn more about the RNG Program by visiting the RNG webpage on the Company's site and also provided information for customers on how to sign up for the program and choose the blend of their choice. The RNG webpage featured information on the environmental benefits of RNG, its source, and a calculator to help customers understand the incremental price impact to their gas bill if they enrolled into the RNG Program and selected a particular RNG blend. Customer communications channels included newsletters, bill inserts, radio, digital (including video and banner ads), radio and skytrain platforms. With the new campaign and unique webpage, views to the RNG landing page (see Table 9 below) increased significantly in 2017, both with organic searches (approximately 50 percent increase), as well as from paid media (approximately 100 percent increase). In addition, one of the digital videos developed had strong results, generating more than 64,000 views on YouTube, and had a view rate of 84 percent on Instagram. Overall, the new customer

awareness campaign was successful and customer participation rates in 2017 showed a 20 percent increase year over year.

In 2018, a campaign with similar messaging was launched but was scaled back as it became apparent that the demand for RNG would exceed the available supply. As a result, the messaging focused on the opportunity to learn more about RNG rather than encouraging customers to enrol into the program.

Through 2019, customer knowledge and awareness expenditures were focused on sponsorship of educational events targeting commercial and residential customer segments.

Overall, from the period of 2016 to 2019, RNG program participation rates have increased close to 50 percent, from 7,478 at 2016 year end to 11,209 at the end of 2019, as can be seen in Table 9 below.

Table 9: RNG Program Customer Participation and Marketing Metrics

Year	Total RNG Customers as at December 31	Unique Pageviews to RNG Program Page
2016	7,478	16,388
2017	8.982	22,296
2018	10,333	11,943
2019	11,209	113

The following table provides a summary of the customer awareness expenditures for the period from 2016 to 2019.

Table 10: RNG Program Customer Awareness Expenditures

Year	Expenditures ($000s)	Description
2016	$100	Customer awareness messaging and customer research study
2017	$246	Development and launch of new awareness campaign into market
2018	$151	New creative continues on a scaled-back basis as indications are that demand will outstrip supply
2019	$29	Customer awareness efforts very limited due to closure of enrolment

Customer participation levels, both existing and new customers, will continue to be an area of focus as further increases in customer awareness can still be achieved. Once additional supply volumes become available to customers in 2021 and the RNG program reopens for customer enrolment, FEI will be able to relaunch its customer education and awareness campaigns to encourage increases in future enrolments as well as retain currently enrolled customers.

8. CONCLUSION

FEI believes that the evidence of increasing enrolments, volume commitments, and revenues generated since implementation of the revised BERC rate methodology, including the Short Term and the Long Term BERC Rates approved in the Decision, have been successful in achieving the three overarching objectives of the BCUC Panel when it issued the Decision.[9] The current BERC rate methodology has enhanced revenue and the recovery of RNG Program costs from RNG customers, FEI has been able to manage biomethane inventory without the need to transfer unsold biomethane, and the BERC Rate mechanism has proven to be robust, effective, and provided for regulatory efficiency as it has been unnecessary to file subsequent applications since the Decision.

Although the RNG Program is currently fully subscribed, FEI is expecting significant new volumes of RNG supply to become available in the later part of 2021. With the new oncoming supply volumes, FEI will be able to reopen enrolment to satisfy the growing customer demand that the program is currently not able to fulfil. FEI expects that once supply becomes available, participation in the RNG Program will continue to grow.

In the meantime, both the supply and demand forecasts for RNG are somewhat fluid and may respond to market signals beyond the BERC rate methodology. Outside factors such as government policies, legislative and regulatory changes, climate change objectives, and the ongoing COVID-19 pandemic can affect the timing and magnitude of both supply and demand. FEI will continue to monitor these developments and assess their impact on the long-term balance between supply and demand.

Given the current state of supply and demand, FEI is satisfied that the BERC rate methodology in place remains appropriate and that changes are not necessary at this time. If warranted in future, FEI will bring forward an application to the BCUC for approval of any changes to the BERC rate methodology or the RNG Program.

[9] Decision, p. 17.

Appendix A
MONTHLY CUSTOMER DATA

Table 1: Number of Customers by Rate Classes and by Offering

	Short-term						Long-term
	Rate 1B	Rate 2B	Rate 3B	Rate 5B	Rate 11B Standard	Total	Rate 11B
Date	# of customers	# of customers	# of customers	# of customers	# of customers	# of customers	# of customers
Jan-16	6,630	125	11	0	4	6,770	0
Feb-16	6,637	127	11	0	4	6,779	0
Mar-16	6,624	128	11	0	5	6,768	0
Apr-16	6,630	130	11	0	5	6,776	0
May-16	6,661	130	11	0	5	6,807	0
Jun-16	6,705	131	11	0	5	6,852	0
Jul-16	6,764	131	11	0	5	6,911	0
Aug-16	6,832	131	11	0	5	6,979	0
Sep-16	6,918	130	11	0	5	7,064	0
Oct-16	6,942	132	11	0	5	7,090	0
Nov-16	7,111	146	13	0	5	7,275	0
Dec-16	7,305	154	14	0	5	7,478	0
Jan-17	7,448	158	15	0	5	7,626	0
Feb-17	7,558	159	15	0	5	7,737	0
Mar-17	7,615	159	15	0	5	7,794	0
Apr-17	7,685	158	16	0	5	7,864	0
May-17	7,767	166	17	0	5	7,955	0
Jun-17	7,894	165	17	0	5	8,081	0
Jul-17	8,036	168	17	0	5	8,226	0
Aug-17	8,158	172	17	0	5	8,352	0
Sep-17	8,296	171	17	0	5	8,489	0
Oct-17	8,481	171	17	0	4	8,673	1
Nov-17	8,625	175	16	0	4	8,820	1
Dec-17	8,781	180	16	0	4	8,981	1
Jan-18	8,900	180	16	0	4	9,100	1
Feb-18	9,035	181	16	0	4	9,236	1
Mar-18	9,104	181	15	0	4	9,304	1
Apr-18	9,216	181	14	0	4	9,415	1
May-18	9,301	184	14	0	4	9,503	1
Jun-18	9,380	191	14	0	4	9,589	1
Jul-18	9,487	192	14	0	4	9,697	1
Aug-18	9,577	197	14	0	4	9,792	1
Sep-18	9,719	195	14	0	4	9,932	1
Oct-18	9,848	198	14	1	4	10,065	2
Nov-18	9,982	202	14	1	4	10,203	2
Dec-18	10,108	205	14	0	4	10,331	2
Jan-19	10,215	203	16	0	4	10,438	2
Feb-19	10,330	208	16	0	4	10,558	3
Mar-19	10,379	207	16	1	4	10,607	3
Apr-19	10,462	206	17	1	4	10,690	3
May-19	10,573	206	17	1	4	10,801	3
Jun-19	10,700	208	17	1	3	10,929	3
Jul-19	10,844	220	17	1	3	11,085	3
Aug-19	10,942	222	17	1	3	11,185	3
Sep-19	10,935	221	17	2	3	11,178	3
Oct-19	10,939	219	17	1	2	11,178	3
Nov-19	11,014	218	17	1	2	11,252	3
Dec-19	10,968	217	17	2	2	11,206	3
Jan-20	10,914	214	16	2	2	11,148	3
Feb-20	10,855	209	16	2	2	11,084	3
Mar-20	10,792	204	15	2	2	11,015	3
Apr-20	10,729	203	15	2	2	10,951	3
May-20	10,706	203	15	2	2	10,928	3

Table 2: Churn Rate[1] by Rate Classes and by Offering

	Short-term					Long-term
	Rate 1B	Rate 2B	Rate 3B	Rate 5B	Rate 11B Standard	Rate 11B Long Term
Date	Churn Rate	Churn Rate	Churn Rate	Churn Rate	Churn Rate	Churn Rate
Jan-16	1.2%	7.2%	27.3%	0.0%	0.0%	0.0%
Feb-16	1.0%	0.0%	9.1%	0.0%	0.0%	0.0%
Mar-16	0.9%	0.0%	9.1%	0.0%	0.0%	0.0%
Apr-16	1.0%	0.0%	9.1%	0.0%	0.0%	0.0%
May-16	1.2%	1.6%	9.1%	0.0%	0.0%	0.0%
Jun-16	1.5%	0.0%	9.1%	0.0%	0.0%	0.0%
Jul-16	1.4%	0.8%	9.1%	0.0%	0.0%	0.0%
Aug-16	1.3%	1.6%	9.1%	0.0%	0.0%	0.0%
Sep-16	1.0%	0.8%	9.1%	0.0%	0.0%	0.0%
Oct-16	1.8%	0.8%	9.1%	0.0%	0.0%	0.0%
Nov-16	1.4%	0.7%	8.3%	0.0%	0.0%	0.0%
Dec-16	1.0%	0.0%	8.0%	0.0%	0.0%	0.0%
Jan-17	1.1%	1.4%	7.7%	0.0%	0.0%	0.0%
Feb-17	0.9%	2.1%	7.7%	0.0%	0.0%	0.0%
Mar-17	1.0%	2.8%	7.7%	0.0%	0.0%	0.0%
Apr-17	1.2%	0.7%	7.4%	0.0%	0.0%	0.0%
May-17	1.3%	0.0%	7.1%	0.0%	0.0%	0.0%
Jun-17	1.1%	2.1%	7.1%	0.0%	0.0%	0.0%
Jul-17	1.5%	1.4%	7.1%	0.0%	0.0%	0.0%
Aug-17	1.3%	0.0%	7.1%	0.0%	0.0%	0.0%
Sep-17	1.0%	0.7%	7.1%	0.0%	0.0%	0.0%
Oct-17	1.2%	1.3%	14.3%	0.0%	25.0%	0.0%
Nov-17	1.1%	0.0%	14.8%	0.0%	0.0%	0.0%
Dec-17	1.1%	0.0%	7.4%	0.0%	0.0%	0.0%
Jan-18	0.9%	2.0%	7.4%	0.0%	0.0%	0.0%
Feb-18	0.7%	2.0%	7.4%	0.0%	0.0%	0.0%
Mar-18	1.0%	2.6%	15.4%	0.0%	0.0%	0.0%
Apr-18	0.9%	2.6%	16.0%	0.0%	0.0%	0.0%
May-18	1.3%	0.0%	8.0%	0.0%	0.0%	0.0%
Jun-18	1.4%	1.3%	8.0%	0.0%	0.0%	0.0%
Jul-18	1.3%	0.6%	8.0%	0.0%	0.0%	0.0%
Aug-18	1.2%	0.0%	8.0%	0.0%	0.0%	0.0%
Sep-18	1.0%	2.5%	8.0%	0.0%	0.0%	0.0%
Oct-18	1.0%	1.9%	8.0%	0.0%	0.0%	0.0%
Nov-18	1.0%	2.4%	8.0%	0.0%	0.0%	0.0%
Dec-18	0.9%	0.0%	8.0%	0.0%	0.0%	0.0%
Jan-19	1.1%	3.6%	7.4%	0.0%	0.0%	0.0%
Feb-19	0.9%	1.8%	7.4%	0.0%	0.0%	0.0%
Mar-19	1.1%	3.0%	7.4%	0.0%	0.0%	0.0%
Apr-19	0.9%	1.8%	7.1%	0.0%	0.0%	0.0%
May-19	1.0%	1.8%	7.1%	0.0%	0.0%	0.0%
Jun-19	1.1%	1.8%	7.1%	0.0%	25.0%	0.0%
Jul-19	1.0%	1.7%	14.3%	0.0%	0.0%	0.0%
Aug-19	1.2%	0.6%	0.0%	0.0%	0.0%	0.0%
Sep-19	0.8%	0.6%	0.0%	0.0%	0.0%	0.0%
Oct-19	0.9%	1.2%	0.0%	0.0%	25.0%	0.0%
Nov-19	0.7%	1.7%	0.0%	0.0%	0.0%	0.0%
Dec-19	0.5%	0.6%	0.0%	0.0%	0.0%	0.0%
Jan-20	0.6%	1.8%	7.4%	0.0%	0.0%	0.0%
Feb-20	0.6%	3.0%	0.0%	0.0%	0.0%	0.0%
Mar-20	0.6%	3.0%	7.7%	0.0%	0.0%	0.0%
Apr-20	0.7%	0.6%	0.0%	0.0%	0.0%	0.0%
May-20	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%

[1] Churn Rate is calculated using the number of customer drop off in the month dived by the average number of customers in the month.

Table 3: RNG Sales Quantity by Rate Classes and by Offering

	RNG Sales Quantity (TJ)							
Date	Rate 1B	Rate 2B	Rate 3B	Rate 5B	Rate 11B	Rate 11B Long term	Rate 30 Off System	Total
Jan-16	9.0	1.4	1.4	0.00	7.60	0.00	0.00	19.5
Feb-16	7.0	0.6	0.3	0.00	7.52	0.00	0.00	15.4
Mar-16	6.3	0.5	0.8	0.00	7.16	0.00	0.00	14.7
Apr-16	3.3	0.6	0.4	0.00	7.28	0.00	0.00	11.5
May-16	2.4	0.2	0.3	0.00	11.50	0.00	0.00	14.3
Jun-16	1.9	0.2	0.2	0.00	7.02	0.00	0.00	9.3
Jul-16	1.7	0.1	0.2	0.00	6.97	0.00	0.00	9.0
Aug-16	1.6	0.2	0.2	0.00	6.92	0.00	0.00	9.0
Sep-16	2.2	0.2	0.2	0.00	7.07	0.00	0.00	9.7
Oct-16	4.5	0.4	0.3	0.00	7.35	0.00	0.00	12.5
Nov-16	7.0	0.9	0.6	0.00	7.38	0.00	0.00	15.8
Dec-16	13.6	1.5	1.0	0.00	5.79	0.00	0.78	22.7
Jan-17	13.8	2.1	0.9	0.00	5.88	0.00	0.00	22.7
Feb-17	11.6	1.6	0.7	0.00	7.61	0.00	0.00	21.5
Mar-17	9.3	1.4	0.8	0.00	9.43	0.00	0.00	21.0
Apr-17	6.7	0.6	1.5	0.00	11.27	0.00	0.00	20.1
May-17	4.3	0.9	1.0	0.00	8.05	0.00	0.00	14.2
Jun-17	2.6	0.4	0.4	0.00	7.61	0.00	0.00	11.0
Jul-17	2.2	0.3	0.6	0.00	8.24	0.00	0.00	11.3
Aug-17	2.0	0.3	1.0	0.00	6.52	0.00	0.00	9.8
Sep-17	2.4	0.3	1.1	0.00	7.59	0.00	0.00	11.5
Oct-17	7.1	1.0	1.6	0.00	4.95	5.92	0.00	20.5
Nov-17	10.9	1.8	3.1	0.00	9.22	5.68	0.00	30.8
Dec-17	15.4	2.5	3.6	0.00	12.31	5.00	0.00	38.8
Jan-18	13.67	2.34	3.48	0.00	2.15	5.92	0.00	27.6
Feb-18	14.35	2.46	1.08	0.00	15.90	5.92	0.00	39.7
Mar-18	11.88	2.08	4.19	0.00	7.79	5.21	0.00	31.2
Apr-18	7.85	0.88	0.98	0.00	8.86	0.55	0.00	19.1
May-18	3.20	0.62	0.57	0.00	2.68	3.44	0.00	10.5
Jun-18	3.08	0.43	0.42	0.00	2.50	5.92	0.00	12.3
Jul-18	2.66	0.30	0.29	0.00	2.43	5.84	0.00	11.5
Aug-18	2.43	0.47	0.31	0.00	2.02	5.39	0.00	10.6
Sep-18	3.83	0.55	0.41	0.00	1.78	5.92	0.00	12.5
Oct-18	7.96	1.09	0.97	0.00	-0.07	9.47	0.00	19.4
Nov-18	11.24	1.66	1.07	0.07	3.30	23.87	0.00	41.2
Dec-18	14.73	2.31	0.68	0.05	1.90	20.89	0.00	40.6
Jan-19	16.0	2.6	3.1	0.24	1.89	24.09	0.00	47.9
Feb-19	18.7	2.9	0.9	0.56	5.33	19.41	0.00	47.8
Mar-19	12.9	2.1	3.3	0.82	3.51	20.43	0.00	43.0
Apr-19	8.0	0.7	1.4	0.57	1.64	18.93	0.00	31.3
May-19	4.2	1.0	0.9	0.22	1.57	14.93	0.00	22.8
Jun-19	3.2	0.4	0.7	0.12	1.37	13.83	0.00	19.5
Jul-19	3.1	0.4	0.7	0.08	1.42	13.83	0.00	19.6
Aug-19	2.9	0.4	0.4	2.50	0.15	1.38	0.00	7.8
Sep-19	3.9	0.6	0.5	0.98	-0.01	0.00	0.00	6.0
Oct-19	10.2	2.0	1.9	1.89	0.00	0.00	0.00	16.0
Nov-19	13.8	2.6	1.2	2.41	0.00	0.00	0.00	20.0
Dec-19	16.6	3.1	2.1	11.62	0.00	0.00	0.00	33.4
Jan-20	17.8	3.6	2.2	-5.71	0.00	0.00	0.00	17.9
Feb-20	15.5	3.0	2.0	2.95	0.00	23.46	0.00	46.8
Mar-20	13.8	2.9	3.1	1.12	0.00	5.56	0.00	26.5
Apr-20	9.3	1.2	0.7	3.85	0.00	10.76	0.00	25.8
May-20	5.0	1.2	3.0	1.26	0.00	8.93	0.00	19.4

Table 4: RNG Sales Revenue by Rate Classes and by Offering

	RNG Revenue ($000)							
Date	Rate 1B	Rate 2B	Rate 3B	Rate 5B	Rate 11B	Rate 11B Long term	Rate 30 Off System	Total
Jan-16	130.19	20.87	20.02	-	109.54	-	-	280.62
Feb-16	100.56	8.85	4.30	-	108.43	-	-	222.14
Mar-16	90.35	7.63	10.82	-	103.17	-	-	211.96
Apr-16	47.33	8.52	5.62	-	104.89	-	-	166.36
May-16	34.15	2.69	4.00	-	165.78	-	-	206.61
Jun-16	27.34	2.42	3.57	-	101.12	-	-	134.46
Jul-16	24.07	2.11	2.90	-	100.48	-	-	129.56
Aug-16	23.16	3.37	3.19	-	99.70	-	-	129.42
Sep-16	32.11	3.58	2.29	-	101.94	-	-	139.92
Oct-16	46.31	3.74	2.79	-	104.67	-	-	157.52
Nov-16	71.00	8.91	6.59	-	46.58	-	-	133.07
Dec-16	139.29	15.61	10.26	-	59.14	-	11.20	235.49
Jan-17	145.88	21.89	9.21	-	62.26	-	3.52	242.76
Feb-17	121.92	17.10	7.17	-	80.22	-	-	226.42
Mar-17	98.44	15.11	8.47	-	99.44	-	-	221.45
Apr-17	70.87	6.32	15.53	-	118.79	-	-	211.51
May-17	45.74	9.25	10.12	-	84.85	-	-	149.96
Jun-17	26.95	3.72	4.63	-	80.15	-	-	115.46
Jul-17	22.88	3.15	6.54	-	86.81	-	-	119.38
Aug-17	21.22	3.14	10.05	-	68.77	-	-	103.18
Sep-17	25.60	3.55	12.05	-	79.98	-	-	121.19
Oct-17	74.98	10.27	16.70	-	54.35	59.16	-	215.46
Nov-17	115.18	19.24	32.62	-	95.44	56.81	-	319.28
Dec-17	161.89	26.05	38.13	-	128.37	50.00	-	404.43
Jan-18	137.67	23.52	35.14	-	23.36	59.16	-	278.85
Feb-18	144.04	24.65	26.21	-	158.89	59.16	-	412.95
Mar-18	119.27	20.89	26.70	-	78.19	52.12	-	297.17
Apr-18	78.75	8.83	9.87	-	88.91	5.48	-	191.85
May-18	32.08	6.25	5.76	-	26.85	34.37	-	105.32
Jun-18	31.00	4.29	4.25	-	25.12	59.16	-	123.82
Jul-18	26.67	3.04	2.92	-	24.43	58.35	-	115.41
Aug-18	24.38	4.73	3.12	-	20.27	53.88	-	106.38
Sep-18	38.41	5.52	4.12	-	17.88	59.16	-	125.09
Oct-18	79.89	10.92	9.76	-	(0.70)	94.90	-	194.76
Nov-18	112.83	16.62	10.77	0.68	33.17	239.00	-	413.07
Dec-18	147.73	23.20	6.84	0.50	19.09	209.25	-	406.62
Jan-19	164.51	27.15	31.39	2.51	19.43	244.64	-	489.63
Feb-19	192.71	29.49	8.76	5.77	54.80	197.85	-	489.38
Mar-19	132.50	21.36	34.21	8.41	36.15	195.99	-	428.63
Apr-19	82.24	7.39	14.64	5.89	16.86	189.33	-	316.35
May-19	42.82	10.61	9.05	2.23	16.17	149.34	-	230.22
Jun-19	32.55	3.65	7.06	1.26	14.06	138.34	-	196.93
Jul-19	31.73	4.73	7.56	0.80	14.58	138.34	-	197.74
Aug-19	30.20	4.46	4.07	25.75	1.58	13.82	-	79.89
Sep-19	40.09	6.47	5.53	10.09	(0.14)	-	-	62.04
Oct-19	104.97	21.02	19.03	19.39	-	-	-	164.41
Nov-19	141.69	26.43	12.57	95.79	-	-	-	276.47
Dec-19	170.31	31.91	21.60	48.56	-	-	-	272.38
Jan-20	187.67	37.64	23.07	(57.91)	-	-	-	190.47
Feb-20	162.86	31.50	20.65	31.12	-	234.59	-	480.72
Mar-20	145.72	30.18	32.46	11.80	-	55.62	-	275.78
Apr-20	98.31	12.68	6.89	40.54	-	107.61	-	266.03
May-20	52.73	12.17	31.68	13.32	-	89.27	-	199.17

Appendix B

SUMMARY OF LONG TERM CONTRACTS TERMS AND CONDITIONS

Table 1: Summary of UBC Long Term BERC Rate Contract

Topic	Terms and Conditions
Contract Term	10 years
Contract Price	$10 per GJ
Quantity over the term of the contract	710 TJs
Minimum Annual Quantity	71 TJs
Additional Quantity	subject to availability, the customer may purchase additional quantity up to the Maximum Annual Quantity.
Maximum Annual Quantity	104 TJs
Early Termination Provision	By providing one year's notice and by paying 50% of the Termination Payment.
Termination Payment	(i)The Minimum Annual Quantity multiplied by (ii) the BERC less the CCRA Rate; and (iii) the lesser of the number of years (calculated to include part years) remaining in the terms of the Agreement if the Agreement had not been terminated and two years.
Rate Escalation	Annual Adjustment of the Contract Price equals: $10 per GJ multiplied by 50% increase of the Consumer Price Index (Canada) over the previous year.
Effective Date	July 1, 2017 (Agreement), October 1, 2017 (BCUC Approval)[1]
Expiry Date	June 30, 2027
Floor Price	The higher of: (a) the Long Term BERC rate or (b) the sum of the following: (i) the approved January 1st CCRA RATE; (ii) carbon tax; (iii) any other taxes applicable to conventional natural gas sales.
Price adjustment after the fifth year	The higher of: (a) the Long Term BERC rate or (b) the sum of the following: (i) the approved January 1st CCRA RATE; (ii) carbon tax; (iii) any other taxes applicable to conventional natural gas sales.

[1] BCUC Order G-64-18.

Table 2: Summary of City of Vancouver Long Term BERC Rate Contract

Topic	Terms and Conditions
Contract Term	5 years
Renewal Term	a term of 5 years
Contract Price	$10 per GJ
Quantity over the term of the contract	360 TJs
Minimum Annual Quantity	Year 1: 83 TJs Year 2: 98 TJs Year 3: 93 TJs Year 4: 33 TJs Year 5: 53 TJs Each year of the renewal term: 40 TJs
Additional Quantity	subject to availability, the customer may purchase additional quantity with a yearly total quantity not exceeding Maximum Annual Quantity .
Maximum Annual Quantity	Year 1: 95 TJs Year 2: 150 TJs Year 3: 150 TJs Year 4: 150 TJs Year 5: 150 TJs Each year of the renewal term: 150 TJs
Early Termination Provision	By providing one year's notice and by paying 50% of the Termination Payment.
Termination Payment	(a)The Minimum Annual Quantity for the lesser of: (i) the remaining term of the agreement, and (ii) 2 years; multiplied by (b) the BERC less the CCRA RATE .
Rate Escalation	Annual Adjustment of the Contract Price equals: $10 per GJ multiplied by 50% increase of the Consumer Price Index (Canada) over the previous year.
Effective Date	October 1, 2018[2]
Expiry Date	September 30, 2023
Floor Price	the sum of the following: (i) the approved January 1st CCRA RATE in each year of the Renewal Term; (ii) carbon tax; (iii) any other taxes applicable to conventional natural gas sales.
Renewal Term Charge	The higher of (a) the Adjusted Long Term BERC rate or (b) the Floor Price.

[2] BCUC Order G-212-18.

Table 3: Summary of Translink Long Term BERC Rate Contract

Topic	Terms and Conditions
Contract Term	5 years
Renewal Term	a term of 5 years
Contract Price	$10 per GJ
Quantity over the term of the contract	1,050 TJs
Minimum Annual Quantity	Year 1: 50 TJs Year 2: 100 TJs Year 3: 150 TJs Year 4: 250 TJs Year 5: 500 TJs
Early Termination Provision	By providing one year's notice and by paying 50% of the Termination Payment.
Termination Payment	(a)The Minimum Annual Quantity for the lesser of: (i) the remaining term of the agreement, and (ii) 2 years; multiplied by (b) the BERC less the CCRA RATE.
Rate Escalation	Annual Adjustment of the Contract Price equals: $10 per GJ multiplied by 50% increase of the Consumer Price Index (Canada) over the previous year.
Effective Date	February 1, 2019[3]
Expiry Date	January 31, 2024
Floor Price	the sum of the following: (i) the approved January 1st CCRA RATE in each year of the Renewal Term; (ii) carbon tax; (iii) any other taxes applicable to conventional natural gas sales.
Renewal Term Charge	The higher of (a) the Adjusted Long Term BERC rate or (b) the Floor Price.

[3] BCUC Order G-19-19.

Attachment 40.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)