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June 14, 2022

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

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 British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 2 on FortisBC Evidence

On January 18, 2021, BCUC initiated the proceeding referenced above. In accordance with the regulatory timetable established in BCUC Order G-106-22 for the review of FortisBC's Evidence, FortisBC respectfully submits the attached response to BCOAPO IR No. 2.

For convenience and efficiency, FortisBC has occasionally provided an internet address for referenced reports instead of attaching lengthy documents to its IR responses. FortisBC intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

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

40.0 Reference: Exhibit A2-5, BCOAPO 1.1

Exhibit B1-9, BCUC 1.3

Exhibit B1-12, ICG 1.7

Preamble: Dr. Lesser's response to BCOAPO 1.1 states:

"Business risk typically is defined as volatility of earnings. Financial risk is typically defined as the risk the firm will be unable to service its debt."

FEI-FBC's response to BCUC 1.3 states: "The FRS requires that the BCUC's determination of a fair return should reflect the business risks (including the Energy Transition risk) that FEI and FBC face".

FEI-FBC's response also states: "All else equal, the FRS requires the BCUC to reflect this higher risk in its determination of allowed return on common equity and capital structure by increasing FEI's allowed ROE and equity thickness.

The FEI-FBC response also states: "The FRS requires the BCUC to consider these factors when determining the impact of Energy Transition on FBC's overall business risk and consequently FBC's capital structure and allowed return on common equity".

FEI-FBC's response to ICG 1.7 states:

"Equity risk has increased for regulated utilities as demonstrated by higher beta coefficients in the CAPM, which suggests higher return expectations for utility investors. Mr. Coyne does not attribute this shift in utility risk to the pandemic, it is coincident with other more structural risk factors, such as the need to respond to the Energy Transition and greater uncertainty regarding future growth prospects".

40.1 Does FEI-FBC agree with Dr. Lesser's definitions for business risk and financial risk?

40.1.1 If not, how would FEI-FBC define the two?

Response:

FortisBC generally agrees with Dr. Lesser's statements but would prefer a more thorough definition as described by Mr. Coyne in his written testimony (Page 73 of Appendix C) of the Application "Evidence of Mr. James Coyne Concentric Energy Advisors Inc. Regarding the Cost of Capital Estimation":

"Business risk is the risk inherent in the company's operations, irrespective of how the company is financed. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs

> including the fair return on, and of, its capital in a timely manner. For utilities such as FEI, these risks also encompass the ability to meet investor expectations for continued earnings growth as public policies and consumer preferences embrace a lower carbon future. Concentric includes operating risk and regulatory risk among other risk factors under this definition of business risk."

As discussed in the evidence, the BCUC has consistently defined business 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. FEI and FBC believe that this definition is consistent with Mr. Coyne's evidence and continues to be appropriate.

Mr.Coyne's evidence further defines financial risk as follows:

> "Financial risk exists to the extent a company incurs fixed obligations in financing its operations as evidenced by the relative percentages of debt and equity in the capital structure. To the extent the company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders."

Credit risk (also known as default risk) and liquidity risk are some common forms of financial risk. Dr. Lesser's definition of financial risk is similar to the definition of credit risk which is risk of defaulting on debt obligations.

40.2 In the determination of the cost of capital, are business risks generally reflected in the determination of the allowed return on common equity or the capital structure or both?

<u>Response:</u>

As explained in Mr. Coyne's evidence (Appendix C), both business and financial risk are important elements of risk that investors consider when establishing their return requirements and should be reflected in the determination of the allowed return on common equity and the capital structure:

> Taken together, business risk and financial risk are the primary elements of risk that investors consider when establishing their return requirements.

Nevertheless, the BCUC's established practice has been to primarily reflect the changes in long-term business risk in capital structure:

> Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks (Exhibit B1-9-6, McShane Evidence,

> Appendix F, p. 39). The Commission Panel does not disagree with Ms. McShane but <u>notes that long-term risk</u>, which Ms. McShane outlines as being of primary importance to the utility investor, <u>is primarily reflected in the equity structure</u> determined for FEI considering the investors' ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt.[1] [Underline added]

FortisBC agrees with the BCUC's statement and applies the same principle to its capital structure proposals for FEI and FBC.

40.3 In the determination of the cost of capital, are financial risks generally reflected in the determination of the allowed return on common equity or the capital structure or both?

<u>Response:</u>

As explained in Mr. Coyne's evidence (Appendix C), both business and financial risk are important elements of risk that investors consider when establishing their return requirements and should be reflected in the determination of the allowed return on common equity and the capital structure:

> Taken together, business risk and financial risk are the primary elements of risk that investors consider when establishing their return requirements.

Mr. Coyne further explains that financial leverage (a main source of financial risk and what is reflected in the approved capital structure) and ROE are inextricably linked and therefore considers this relationship by comparing the weighted ROEs (authorized equity return X deemed equity ratio) for FEI and FBC with other large investor-owned utilities. Hamada adjustment, discussed in Dr. Lesser's report and Mr. Coyne's evidence (at pages 157 and 160), can also be used to adjust for differences in financial leverage between companies for which the return is being established and the proxy group so that the variances in financial leverage (financial risk) of companies are reflected in the allowed return.

[1] 2013 Decision, p. 24.

40.4 Based on the first quote in the preamble from BCUC 1.3, does FEI-FBC consider Energy Transition risk to represent a business risk (but not a financial risk)?

40.4.1 If not, please explain why.

Response:

FEI and FBC do not believe that the first quote in the preamble implies that the Energy Transition risk is exclusively a business risk. As explained in response to BCUC IR1 4.1.1, the term "Energy Transition" risk is a new umbrella term used to cover a broad spectrum of risk, including financial risk. FortisBC's filed evidence in this proceeding as well as a number of IR responses discuss how credit rating agencies are increasingly considering the Environmental, Social and Governance (ESG) factors in their rating methodologies (please refer to the response to BCUC IR1 8.1) and how the Energy Transition risk can impact credit spreads and financing of fossil-fuel related projects. For more information, please refer to the response to BCUC IR1 4.2.1 as well as Section 6.3.1 (titled ESG considerations significantly impacting the companies' long-term financial risk) of FortisBC's evidence.

40.5 The second and third quotes from BCUC 1.3 state that the impact of the Energy Transition risk must be considered in the determination of allowed return on common equity and capital structure by increasing FEI's allowed ROE and equity thickness. If it's considered in the determination of both, how does one avoid double counting the impact/effect of Energy Transition risk?

Response:

As explained in the response to BCOAPO IR2 40.2 and 40.3, both financial and business risks (whether associated with Energy Transition or other factors) must be considered in the determination of allowed return on common equity and capital structure. Regulators can use their judgement informed by the expert evidence and other available information on the record to adjust either allowed ROE and/or equity thickness to account for the changes in financial and business risks of the utility over time and relative to the proxy group.

As further explained in response to BCUC IR2 79.2, the recommended equity ratio of 45.0 percent reflects the increased business risk of FEI as compared to 2016 and relative to the proxy group companies, while the equity return of 10.1 percent is based on the current and projected market conditions and average industry risk captured in the DCF and CAPM models. This basis of analysis prevents any double counting.

40.6 Based on the response to ICG 1.7, does the CAPM model already capture the risks associated with Energy Transition?

40.6.1 If not, why not?

Response:

Concentric provides the following response:

To some extent the CAPM may capture the Energy Transition risk through the Beta coefficient for some proxy group companies, although for FEI Energy Transition risk is certainly higher than for the U.S. Gas proxy group overall, 50 percent of which provide service in jurisdictions that have legislation prohibiting natural gas bans. In addition, the CAPM results are higher than the DCF results, and Mr. Coyne's ROE recommendations for FEI and FBC are based on an average of the two models. Furthermore, business risk is typically accounted for through the deemed or authorized equity ratio rather than the authorized ROE, and the authorized equity ratios for the U.S. Electric and U.S. Gas proxy group companies are well above those for FEI and FBC.

40.7 Does FEI-FBC agree that the risks of Energy Transition will be captured by the growth rates provided by market analysts and therefore already captured in the DCF model?

40.7.1 If not, why not?

Response:

Concentric provides the following response:

As explained starting on page 74 of Mr. Coyne's report, Energy Transition risk is a relatively new risk for regulated utilities, and environmental policies are developing and evolving in each individual province or state. The regulatory framework for responding to the issues surrounding the Energy Transition is still in formation. The growth rates and stock prices for these companies may reflect some preliminary assumptions by investors about the Energy Transition risk for these companies which represents an average risk utility. However, FEI is not an average risk utility that would be represented by these estimates.

41.0 Reference: Exhibit B1-9, BCUC 23.5

Preamble: The response states:

> "While FortisBC is hopeful that this will continue to be the case, the potential remains that any regulatory decision with the potential to affect Aboriginal rights and title could result in an Indigenous group bringing a judicial review application."

41.1 Please confirm that, at the time of the BCUC's previous GCOC Decisions for both FBC and FEI, there was the potential "that any regulatory decision with the potential to affect Aboriginal rights and title could result in an Indigenous group bringing a judicial review application".

Response:

Confirmed; however, the adoption of the United Nations Declaration on the Rights of Indigenous Peoples, including its requirements to seek the free, prior and informed consent of Indigenous Peoples, increases the likelihood of such a review.

42.0 Exhibit B1-9, BCUC 27.1 and 27.2

42.1 With respect to BCUC 27.1, does the degree to which a higher risk is attributed to power generation as opposed to distribution also depend on the type of power generation being employed (e.g., nuclear vs. fossil-fuel vs. hydro-electric)?

<u>Response:</u>

As described in the response to BCUC IR1 56.1, there is less risk associated with utilities that have a diversified generation portfolio than with those that rely on a single generation type. Within that evaluation, consideration is given to the type of generation, however, this is done in concert with a number of other factors, making a simple ranking of generation types as they relate to risk difficult.

In the *Moody's Rating Methodology: Regulated Electric and Gas Utilities* referenced in the response to BCUC IR1 56.1, additional commentary notes that:

> Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score higher in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will score lower.
>
> In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources.

It is more likely that nuclear and fossil-fuel would be considered challenged and threatened sources of generation as compared to hydro-electric. However, in the case of FBC, the mix of generation is unchanged from 2013.

Please also refer to the response to BCUC IR2 71.4.

42.2 With respect to BCUC 27.2 and the reference to FBC's water licences issued under the Water Act (British Columbia), when were the water licences first granted?

42.2.1 Since that time have the water licences ever been materially altered to the detriment of FBC?

42.2.2 Since that time have the water licenses ever been materially altered to the benefit of FBC?

42.2.3 Does FBC currently have any indication that the water licences will be altered materially in the future to its detriment?

Response:

There are three different types of licences or orders held by FBC in relation to the use and storage of water:

1. Water licences for Kootenay Lake and each of the plants;
2. International Joint Commission (IJC) order on Kootenay Lake; and
3. *International River Improvements Act* licence.

The water licence history of the FBC plants is long and complex as FBC has been generating electricity since the late 1800s and each plant has its own history. From a risk perspective, the key licences and orders are those relating to Kootenay Lake.

The current licence for FBC storage in Kootenay Lake is Final Water Licence (FWL) 69723 issued November 7, 1992 with a date of precedence of May 8, 1924. Over the years, the changes to the water licence addressed an increase in storage up to the full 6 feet of storage (maximum storage elevation of 1745.32 feet) as well as changes in ownership. FBC is not anticipating any changes to its current water licences at this time.

The IJC order on Kootenay Lake dates to November 11, 1938. There have been no further orders issued relating to current Kootenay Lake operations since that time. However, the IJC is currently considering the need to open the 1938 Kootenay Lake order[2] in order to incorporate additional terms that potentially could restrict FBC's generation options.

The current *International River Improvements Act* licence dates to July 11, 2010 and is valid for 25 years. This licence was first issued on August 14, 1956. The current licence did not impact the ability of FBC to generate power from its plants as compared to previous licences. However, the potential for future licence renewals to do so remains.

FBC does not believe the water licences issued under the provincial *Water Sustainability Act* (and its predecessor legislation) have been materially altered to the detriment of FBC.

[2] 2021 Public Meeting Minutes (ijc.org), please see question 5.

42.3 With respect to BCUC 27.2 and the reference to the Columbia River Treaty between Canada and the United States as well as the International Joint Commission's order for Kootenay Lake, when were these first established?

Response:

The Columbia River Treaty between Canada and the United States was ratified in 1964.

Please also refer to the response to BCOAPO IR2 42.2 for discussion of the IJC order.

42.3.1 Since that time have Government authorities in Canada and the United States ever used their powers under the Treaty and the International Joint Commission to regulate water flows in a manner that could adversely affect the amount of water available for the generation of power in order to protect environmental values?

Response:

FBC is not a party to the Columbia River Treaty (CRT) and is not an expert on how treaty operations may have impacted the generation of power on the Columbia River System as a whole. FBC does not believe that treaty operations have negatively affected FBC power generation to date. Under the CPA with BC Hydro, FBC's entitlements of energy and capacity are based on the flows that would have occurred without the CRT Duncan and Libby dams being in existence.

However, future CRT operations may impact FBC entitlements under the CPA if such operations would potentially affect the water available to FBC in the absence of the CRT Duncan and Libby dams. Salmon restoration on the Upper Columbia is one example of future changes that could occur under the CRT[3] that may impact FBC water availability for generation entitlement calculations.

As mentioned in FBC's business risk evidence (Appendix B), FBC assesses its overall risk in terms of security of supply as similar to the 2013 Proceeding.

Please also refer to the response to BCOAPO IR2 42.2.

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[3] Columbia River Treaty Info Sessions | Columbia River Treaty (gov.bc.ca)

42.4 Has FBC specifically assessed the likelihood that prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which (in turn) would reduce the Corporation's entitlement to capacity and energy under the Canal Plant Agreement?

42.4.1 If yes, please provide the report setting out the assessment and its conclusions?

Response:

No, FBC has not performed such an assessment. Nevertheless, the perceived risk of a significant and sustained loss of precipitation over the headwaters of the Kootenay River on FBC's capacity and energy entitlements under the CPA is understood by investors as it is discussed in FBC's Management and Discussion Analysis (Appendix D) filed with the Securities Commission.

43.0 Reference: Exhibit B1-9, BCUC 28.1

Preamble: The response states:

> "Governments' overall climate change and energy policies are generally favourable to electric utilities, including FBC. The extent of this benefit is tempered by the fact that an over-reliance on electrification as a GHG emission reduction solution could lead to the requirement for significant additional investment in capital infrastructure to support the new capacity requirements on FBC's system with increased costs for FBC and its customers.".

The response also states:

> "Unlike BC Hydro, FBC has no ability to socialize its costs or deeply discount the rates it offers to its customers which means the potential additional investment can impact its price competitiveness".

43.1 With reference to FortisBC's current 2021 LTERP Application, please comment on the ability of FBC's current infrastructure to support new capacity requirements.

Response:

The ability of FBC's current infrastructure to support new capacity requirements depends on the pace and degree of growth of new electrification loads on the FBC system. As discussed in the response to CEC IR1 48.1, electrification, including for home and business space and water heating and relating to transportation, would 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 to be added gradually over time. However, as discussed in Section 4.1 of Appendix B, a drastic increase in customer consumption of electricity can drive significant additional investment in more capital infrastructure to support the new capacity requirements. 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.

Section 6.4 of the LTERP discusses FBC's anticipated system reinforcements to meet capacity requirements through 2030. FBC notes that there is considerable uncertainty in the peak demand forecasts over the next decade and that changes in peak demand forecasts may result in the advancement or deferral of some projects. As an example, previous studies indicated that the the Kelowna Bulk Transformer Capacity Addition project would not be required until the mid-2020s[4]. However, updated summer peak demand forecasts and the constraints associated with equipment emergency loading limits indicated that the Kelowna Bulk Transformer Capacity Addition project or an alternative project or resource could be required sooner than originally

[4] In the Application for Approval of Treatment for Major Project Capital Expenditures under the Multi-Year Performance Based Ratemaking Plan for 2014-2019, FBC indicated that the Kelowna Bulk Transformer Capacity Addition was deferred beyond PBR Term.

expected. Based on the more recent information, the FBC CPCN Application for this project was approved by the BCUC in November of 2020 and the project is currently in the construction phase. As another example, recent system studies indicated that the 20L Upgrade project will not be required until the late-2020s based on recent load forecasts. However, due to recent transmission interconnection requests and interest from new large load customers in 2021, this project may be required sooner.

Section 6.5.4 of the LTERP explores the potential peak demand impacts of some of the LTERP load scenarios on FBC's system, Kelowna in particular, in terms of potential projects required to meet the additional load and their associated costs over the 20-year planning horizon. This initial high-level analysis indicates that significant additional projects would be required to meet the additional peak demand requirements of the Kelowna area at the 550 MW level by 2040. Should these scenarios begin to emerge, FBC could implement measures to mitigate the increases in system peak demand requirements. Mitigation measures could include adding options for non-firm large load curtailment during peak demand periods, shifting EV charging loads off peak periods and installing a large capacity generation resource in the Kelowna area.

43.2 With respect to the second reference in the preamble, what "costs" is BC Hydro able to socialize that FBC cannot?

Response:

"Costs" as referenced in the preamble refers to any cost associated with providing service that would normally (and most certainly in the case of FBC), be recovered in rates and from ratepayers of the utility. In the case of BC Hydro, socialization across other BC Hydro ratepayers is provided for when rates are discounted from the level they would be at if cost-based. One example is the *Clean Industry and Innovation Rate* (Rate Schedule 1894), which had its approval mandated by Order in Council No. 657 (2020).

Further socialization of costs can occur on a broader basis when costs associated with providing service to BC Hydro customers are effectively precluded from ever being recovered in rates, such as occurred in 2019 when the Province wrote down $1.1 billion in deferred expense costs carried by BC Hydro to reduce the amount of pending rate increases.

Another form of indirect cost socialization benefiting BC Hydro relates to taxpayer funded rebates for programs that provide financial incentives for customers to switch from other forms of fuel to electricity like those currently being provided for electric heat pumps, although FBC customers can also benefit from these rebates if eligible.

43.3 With respect to the second reference in the preamble, please explain what ability to "deeply discount rates" that BC Hydro has but FBC does not.

Response:

Please refer to the response to BCOAPO IR2 43.2.

43.3.1 Please explain how this inability to deeply discount rates (when compared to BC Hydro) means potential additional investment can impact FBC's price competitiveness.

Response:

The impact that a general investment in capital infrastructure, required to support electrification, would have on rates could be mitigated to some extent by an increase in load. FBC's ability to attract new load is hampered when non-cost-based rates are offered by BC Hydro, or when the general level of rates of a neighbouring utility, such as BC Hydro, are artificially lowered or socialized (for example through write-down of costs).

44.0 Reference: Exhibit B1-9, BCUC 29.1

44.1 Which of projects listed involve the construction/expansion of FBC facilities into "green-field" areas where FBC does not currently have facilities or permits?

Response:

Please refer to the table below for commentary on the FBC projects listed in the response to BCUC IR1 29.1.

Project Name	Nature of Project Construction
Reconductor 51 Line and 60 Line (DG Bell to OK Mission)	Brownfield within existing right of way. May require minor additional land acquisition to accommodate line routing, to be determined during detailed transmission line design.
Reconductor 52 Line and 53 Line (RG Anderson to Huth)	Brownfield within existing right of way. May require minor additional land acquisition to accommodate line routing, to be determined during detailed transmission line design.
DG Bell Terminal – distribution transformer addition	Brownfield expansion within existing fee-simple property.
AS Mawdsley Terminal – transformer replacement	Preliminary design is currently underway. May involve construction on a new greenfield site, or brownfield replacement depending on the results of the project alternatives comparison.
Saucier Substation – distribution transformer addition	Brownfield expansion within existing fee-simple property.
Duck Lake Substation – distribution transformer addition	Brownfield expansion within existing fee-simple property.
Kaleden Substation – transformer replacement	Brownfield equipment replacement. May require minor additional land acquisition, to be determined during detailed station design.
Christina Lake Substation – substation rebuild	Brownfield rebuild preferred. May require minor additional land acquisition, to be determined during detailed station design.

45.0 Reference: Exhibit B1-9, BCUC 30.1

45.1 Does FBC sell surplus power in the wholesale power markets?

45.1.1 If yes, does the analysis as to the impact of higher wholesale market prices (as set out in BCUC 30.1) also take into account the impact on revenues from "export" sales?

Response:

FBC generally only sells surplus capacity to Powerex under the Capacity and Energy Purchase and Sale Agreement (CEPSA), and does not typically have any surplus energy to sell to Powerex (or otherwise) in the wholesale power market. FBC did not include any analysis on surplus capacity sales revenue in its response to BCUC IR1 30.1, but rather provided an illustrative response based on the effect of wholesale energy prices and FBC's ability to offset BC Hydro Power Purchase Agreement energy.

Furthermore, the revenue that FBC receives from Powerex for its capacity sales is based on both a fixed payment and a variable payment. The variable payment considers the daily volume that is sold, and the value is based on a formula that is derived from the Mid-C peak and off-peak day ahead spread. Therefore, all else equal, if peak and off-peak prices both increased by the same amount, there would be no change to the revenue that FBC receives from its surplus capacity.

Recent Mid-C day-ahead data suggests that the spreads between peak and off-peak prices are beginning to shrink, putting the FBC capacity sales revenue at risk. This trend is increasing in the current Mid-C day ahead market, and is also beginning to appear in long-term, industry wide, price forecasts.

46.0 Reference: Exhibit B1-9, BCUC 33.1

Preamble: The response states:

> "However, due to the increase in diversity being in large part due to the addition of cryptocurrency load, which is viewed as inherently risky, the added diversity is not considered to mitigate risk."

46.1 Excluding cryptocurrency load, how has FBC's industrial diversity changed since 2013?

Response:

The impact of adding the cryptocurrency load in 2020 is to reduce the proportion of total load attributable to the other sectors across the board. In other words, the change in diversity as compared to 2013 is consistent with or without the cryptocurrency load. There would still be a shift from Forestry/Pulp/Paper to Government/Education/Health but, by excluding cryptocurrency load, their proportion of total load would both be higher.

47.0 Reference: Exhibit B1-9, BCUC 33.3

Preamble: The response states:

"The existing contracts with Industrial customers do not contain take-or-pay clauses and/or any early termination penalties."

47.1 Please confirm that under FBC's RS31 for large industrial customers the Billing Demand used for the Wires Charge is:

The greatest of:

i. Eighty percent (80%) of the Contract Demand, or

ii. The maximum Demand in kVA for the current billing Month; or

iii. Eighty percent (80%) of the maximum Demand in kVA recorded during the previous eleven Month period.

Response:

Confirmed.

48.0 Reference: Exhibit B1-10, BCOAPO 11.3

48.1 With respect to BCOAPO 11.3, which two industrial sectors does FBC consider to potentially have the greatest volatility in year to year load?

Response:

FBC identifies on page 31 of Appendix B to the filed evidence that cryptocurrency and forestry are two industries that face inherent volatility and exposure to world markets. These are the two industrial sectors that FBC considers to have the greatest potential for volatility in year to year load.

49.0 Reference: Exhibit B1-9, BCUC 36.2

Preamble: The response expresses concern that:

> "A generic approach to deferral account financing costs could put further downward pressure on FBC's financial metrics that are already weak and consistent with non-investment grade credit. This would result from any additional debt required to finance FBC's interest-return-only deferrals, without an offsetting requirement for equity."

49.1 Does FEI-FBC agree that the example regarding the OPEB Liability Account subsequently cited in the response demonstrate that, even under a generic approach, the BCUC is open to considering specific circumstances and issues where warranted?

49.1.1 If not, why not?

<u>Response:</u>

FortisBC agrees that the BCUC was open to considering the specific circumstances and issues surrounding the FBC OPEB Liability Account and amended the financing of the account appropriately upon reconsideration. That said, the amount of exceptions that may require reconsideration is unknown at this point, and may require more work in the reconsideration / exception granting process than would have otherwise been required by requesting individual deferral account returns via revenue requirement applications, CPCN applications, etc. FortisBC has already considered the specific circumstances of each deferral account when requesting each account's return, and the BCUC has the ability to test that request in the respective application. As such, FEI-FBC believe the longstanding approach is a more efficient and effective approach for determining deferral account returns as opposed to on a potentially-widespread "exception" basis. In other words, there is no value to having a generic rule for existing (or future) deferral accounts, when the appropriate return has already been determined for existing accounts and there is already a process in place to set returns for future accounts.

Regardless, the BCUC decision to revisit deferral account financing costs itself creates uncertainty and indicates higher regulatory risk.

50.0 Reference: Exhibit B1-9, BCUC 58.1

Preamble: The response states:

> "As shown in the Attachment, since 2010, the average authorized ROE for integrated electric utilities has been 44 basis points higher than T&D companies, while the average equity ratio has been 1.93 percentage points higher for companies than own regulated generation."

50.1 With respect to the historical average authorized ROEs, given the variation in authorized ROE across both groups of utilities (i.e., integrated electric utilities and T&D electric utilities) is the 44 basis points difference statistically significant?

Response:

Concentric provides the following response:

Mr. Coyne did not test for statistical significance. Mr. Coyne's analysis quantifies the historical differential based on the decisions of U.S. regulators involving electric utilities since 2010. The ownership of generation assets is considered higher risk by credit rating agencies and equity investors, but other risk and regulatory factors could also affect the allowed return differential.

50.2 With respect to the historical average equity ratio, given the variation in authorized ROE across both groups of utilities (i.e., integrated electric utilities and T&D electric utilities) is the 1.93 percentage point difference statistically significant?

Response:

Please refer to the response to BCOAPI IR2 50.1.

51.0 Reference: Exhibit B1-12, ICG 2.2

Exhibit B1-9, BCUC 23.2

Preamble: The response to ICG 2.2 states:

> "Therefore, the risks and opportunities to FBC and its customers, including the impact on FBC's revenues or the potential for incremental costs arising from the duplication of utility infrastructure, are unclear. However, on balance and as mentioned in the preamble, this additional uncertainty represents a risk to FBC as it can result in reduced rate base and revenue".

51.1 Is there anything in the BCUC's Indigenous Utilities Regulation Inquiry Report to suggest that FBC could be required to sell its assets to an Indigenous utility under terms that would disadvantage either FBC or its ratepayers?

<u>Response:</u>

The BCUC Indigenous Utilities Regulation Inquiry Final Report did not directly suggest that FBC could be required to sell its assets to an Indigenous utility. However, the Final Report did note the potential for Indigenous utility impacts to result in losses to an incumbent utility, including as a result of stranded assets. The Final Report also referenced the acquisition of existing utility assets by a First Nation.

The Final Report stated at pages 65 and 66 that:

> The effective transfer of service area from the incumbent utility and the stranding of the incumbent utility's assets can be viewed as a seizure of the incumbent utility's assets unless compensation is provided or a compelling public interest reason exists.
>
> There is no evidence in this Inquiry of a circumstance where the ownership of distribution infrastructure has been transferred, nor are we aware of any such instance in British Columbia. However, in our view, in order for Indigenous peoples to "freely pursue their economic development" it is not enough to enable a First Nation to determine its means of regulation and effectively transfer the regulated public utility's rights to the First Nation but then leave a significant barrier- in the form of the incumbent utility's distribution assets - in place. To do so would be counter to UNDRIP Article 3 …
>
> …
>
> As well as, Article 4 …
>
> …

> We therefore consider it consistent with Articles 3 and 4 of UNDRIP that the First Nation has the opportunity to acquire the existing assets at a price that is fair to both the First Nation and the incumbent utility.
>
> …
>
> In any event, we are of the view that the incumbent public utility should be compensated for its losses. Reasonable compensation for the stranded assets could be the book value, which represents the portion of costs that are unrecovered, or the market value.

The Final Report recommended that the UCA be amended to enable the BCUC to determine, in a public proceeding, fair compensation for an incumbent utility, if the operations of an Indigenous utility materially impact that incumbent utility (Final Recommendation 21). To date, no such amendments have been made to the UCA.

52.0 Reference: Exhibit B1-13, RCIA 10.1

Preamble: The response states:

> "FBC notes that not all components of each generating unit have been upgraded or replaced since their original construction. A generating station and the associated dam can include other assets which are used directly or indirectly in the generation of electricity and assets which have not been upgraded."

52.1 Does FBC perform period asset condition assessments for the major components of its generating stations?

Response:

FBC performs a number of inspections on all of its facilities and major components of its generating stations. The maintenance management system includes routine, annual and major unit inspections that inform decisions around the condition of assets and future maintenance needs. However, the current systems do not provide information related to an overall asset condition assessment for the major components of its generating stations. Asset condition assessments are complex and resource-intensive undertakings and are therefore conducted primarily in response to findings made during the completion of inspection and maintenance programs.

52.2 If yes, please provide a summary the overall "condition" of each of FBC's generating stations as of 2013 and as of 2020, highlighting any major changes.

Response:

Please refer to the response to the BCOAPO IR2 52.1.

53.0 Reference: Exhibit B1-11, CEC 49.2

Preamble: The response states:

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

53.1 Are there instances where the BC government's policies or directives with respect to BC Hydro have increased BC Hydro's costs?

<u>Response:</u>

Some of the BC government's policies and directives with respect to BC Hydro have increased BC Hydro's costs. For example, the government mandate to acquire power from Independent Power Producers was noted in a 2019 report to government as having the results that BC Hydro, "…paid too much for the energy it bought." Also, it seems likely that the Site C generation project will impose costs on BC Hydro's operations; however it is unclear whether or not the drive for electrification of the economy and resulting increased demand can offset those costs in a manner that can offset the impact on rates. It is also not clear whether, in the future, the BC government would further use taxpayer funds to socialize cost increases.

54.0 Reference: Exhibit B1-10, BCOAPO 13.4

54.1 Does FBC consider there to still be uncertainty within the consultation environment due to legislative changes (i.e., 2018 BC Environmental Assessment Act 2018 and Declaration on the Rights of Indigenous Peoples Act)?

54.1.1 If yes, what actions is FBC undertaking to clarify consultation requirements in light of these changes?

Response:

Yes, uncertainty remains within the consultation environment due to legislative changes. FBC continually monitors developments in the consultation environment resulting from legislative changes and seeks clarity on evolving requirements from regulators and Indigenous groups.

54.2 Has the number of Indigenous groups actually participating in regulatory processes (such as: registering as intervenors) increased since 2013 or is it more the number of Indigenous groups seeking to actively participate in consultations with FBC on its proposed projects that has increased?

Response:

FBC has experienced both an increase in the number of Indigenous groups participating in FBC's regulatory processes and an increase in the nations actively participating in consultations since 2013.

54.3 Recognizing these changes in consultation requirements, has FBC made any changes to its planning processes in terms of either the time allotted for consultation or when consultation is first initiated?

Response:

FBC has and continues to evolve its planning processes over time and endeavours to initiate conversations as early as possible to ensure input from Indigenous groups, and then allocates time to ensure Indigenous groups have the necessary time to provide that input.

55.0 Reference: Exhibit B1-10, BCOAPO 14.3 and 14.4

Preamble: The response states:

"In 2014, the revised PPA with BC Hydro came into effect, and changes to that contract limited FBC's ability to displace PPA energy with more cost-effective market power, thereby potentially increasing power supply cost. In addition, the revised PPA also limited FBC's right to less expensive, embedded cost energy from BC Hydro, to 1,041 GWh and priced any energy taken over that amount at the Tranche 2 energy rate, which is based on BC Hydro's Long Run Marginal Cost of firm energy."

55.1 Since the revised PPA came into effect, in how many years has contractual limit on FBC's ability to displace PPA impacted its ability to displace PPA energy with more cost-effective market power?

Response:

As per the table below, for the last three years under the prior PPA agreement, FBC's average purchases under the PPA were 471 GWh. Under the revised PPA, FBC's average purchases have been 546 GWh. While it is difficult to say what the purchases under the revised PPA would have been in any individual year if the terms of the previous PPA had continued, FBC believes that the average PPA purchases under the revised PPA most likely have been about 75 GWh a year higher than they would have been under the previous PPA. The exception to this is the current year and potentially future years due to the high market prices that currently exist. However, the changed terms of the PPA still impact FBC in a high-priced market environment since FBC can only purchase 1,041 GWh at Tranche 1 energy rates.

In summary, in low priced markets when FBC would seek to buy more market power, the changes in the revised PPA appear to have limited FBC's ability to displace PPA energy with more cost-effective market power by about 75 GWh a year, while in high priced markets when FBC would seek to buy more PPA energy, the changes limit FBC's ability to purchase cost-effective PPA Tranche 1 priced energy.

Contract Year	FBC Actual PPA Purchases (GWh)
2011/12	512
2012/13	376
2013/14	526
Average Purchases, Prior PPA	**471**
2014/15	570
2015/16	518
2016/17	538
2017/18	482
2018/19	544
2019/20	632
2020/21	538
Average Purchases, New PPA	**546**

55.2 Since the revised PPA came into effect, how many years would FBC have purchased more than 1.041 GWh from BCH if the additional purchases could have been made at the Tranche 1 energy rate?

Response:

FBC would not have purchased more than 1,041 GWh from BC Hydro in any year since the revised PPA came into effect, even if those purchases could have been made at the Tranche 1 energy rate. This is because, since that time, FBC has been able to purchase a substantial portion of its requirements from the wholesale market which has been less expensive, until recently.

However, the Mid-C market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. FBC has also experienced higher than expected load growth on the system because of large new customer load. Ongoing lack of forward market opportunities combined with faster than anticipated load growth will likely increase FBC's PPA take to the Tranche 1 energy limit of 1,041 GWh within a couple of years if conditions persist.

56.0 Reference: Exhibit B1-10, BCOAPO 34.1

Exhibit A2-5, BCOAPO 1.1

Preamble: Dr. Lesser's response to BCOAPO 1.1 states:

> "Business risk typically is defined as volatility of earnings. Financial risk is typically defined as the risk the firm will be unable to service its debt."

The response to BCOAPO 34.1 states:

> "In this sense, the flow-through deferral account can mitigate FBC's short-term demand and power supply cost risks. However, it does not change FBC's long-term risks associated with owning capital intensive generation assets (asset concentration risks) and the risk of inability to fully recover invested capital".

56.1 Based on Dr. Lesser's definitions of business risk and financial risk, does FBC's response apply to both FBC's business risks and its financial risks from owning power generation?

Response:

As explained in response to BCOAPO IR2 40.1, FEI and FBC would prefer to use Mr. Coyne's definition of business and financial risk.

BCOAPO IR1 34.1 poses a question with regards to FBC's flow-through deferral account and its impact on power generation risk. In response, FBC clarified that deferral accounts are only effective in reducing the short-term risk and do not change FBC's long-term risk associated with owning generation assets. Demand and power supply risks as discussed in the response to BCOAPO IR1 34.1 are forms of business risk. Flow-through deferral accounts are, therefore, effective in mitigating some of FBC's short-term demand and power supply risk. Deferral accounts, including the flow-through deferral account, can also impact financial risk. As explained in response to BCUC IR2 66.1, changes to deferral accounts, such as the flow-though deferral account, can impact the values of financial metrics used in credit rating agencies' rating methodology. In addition to short-term business risk and financial risk, material changes in the use and treatment of deferral accounts, in ways that may affect investors' confidence in regulatory support and the regulatory environment, can also have long-term business risk impacts in the form of regulatory risk.

In the 2012 GCOC Stage one decision, the BCUC agreed with FortisBC's expert that both the capital structure and the ROE incorporate elements of long-term and short-term risks, but noted that the long-term risk is primarily reflected in the capital structure. Considering that deferral accounts are designed to manage short-term risk and given their impact on financial risk as well as their potential impact on long-term business risk, the impact of deferral accounts, including the flow-through deferral account, should be considered in both ROE and equity thickness.

As explained in FBC's business risk evidence, there has not been any material change in FBC's short-term risk as a result of changes to deferral accounts although the BCUC decision to consider a more generic approach to deferral account financing creates uncertainty for FBC and investors and can potentially increase FBC's long-term regulatory risk.

57.0 Reference: Exhibit B1-10, BCOAPO 35.1

57.1 For each of the referenced scenarios what do the GWh increases for 2030 and 2040 represent as a percentage of the BAU forecast load in those years?

<u>Response:</u>

For Scenario 3 (Deep Electrification), the increase in annual energy load (i.e. GWh increases) in 2030 and 2040 relative to the BAU load forecast is 10.3 percent and 23.8 percent, respectively. For Scenario 4 (Diversified Energy Pathway), the increase in annual energy load in 2030 and 2040 relative to the BAU load forecast is 17.6 percent and 30.7 percent, respectively. Hydrogen production in Scenario 4 results in the higher annual energy requirements.

58.0 Reference: Exhibit B1-10, BCOAPO 38.1

Preamble: The response states:

> "Mr. Coyne's ROE analysis considers both current and forward- looking market data. For example, his DCF models use recent historical dividend payments and stock prices to calculate the dividend yields, forecast earnings per share growth rates from equity analysts, and projected GDP growth. His CAPM model uses a projected risk-free rate, five year Beta coefficients from Value Line and Bloomberg, and both a historical and forward- looking market risk premium".

58.1 The issue underpinning the original question was whether using a combination of values/assumptions where some are drawn from current/recent market conditions while others are drawn from forecast market conditions is appropriate and will yield reasonable results when the current/recent market conditions varying significantly from the forecast. Please comment on this issue/question.

<u>**Response:**</u>

Concentric provides the following response:

The original question cited Mr. Coyne's response to the BCUC seeking comments on circumstances warranting initiation of a cost of capital proceeding. He stated "My view is that a 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. The cost of capital should be forward-looking and should rely on current market data and conditions in the economy and capital markets." (Coyne report, p. 156). While Mr. Coyne did not state which data should be current or forward looking, current market data is often used as a test for whether a new cost of capital proceeding should be initiated, even though the cost of equity is forward-looking. To the extent reasonable estimates are available, Mr. Coyne utilizes projected data (e.g., forecast interest rates, projected EPS growth rates, projected GDP growth, adjusted Betas, which reflect the tendency of beta to revert to the market average of 1.0, etc.). However, projected market data is not always available for each model input. Under those circumstances, it is appropriate to use a combination of current/recent market conditions and forecasts to estimate the cost of equity. For example, Mr. Coyne has used an average of the historical market risk premium ("MRP") and a forward-looking MRP in the CAPM analysis.

59.0 Reference: Exhibit B1-9, BCUC 24.1

Preamble: The response states:

> "FEI's and FBC's proposed ROEs and capital structure are a function of both capital market conditions as reflected in Concentric's financial models as well as utility specific risk considerations.".

59.1 With respect to FEI, please indicate how its utility specific risk considerations impacted the proposed ROE and capital structure (relative to the results of Concentric's financial models).

<u>Response:</u>

Concentric provides the following response:

Mr. Coyne captured utility specific risk for FEI in the requested equity ratio of 45.0 percent, while capital market conditions and average business risk as represented by the proxy companies are reflected in the recommended ROE of 10.1 percent.

59.2 With respect to FBC, please indicate how its utility specific risk considerations impacted the proposed ROE and capital structure (relative to the results of Concentric's financial models).

<u>Response:</u>

Concentric provides the following response:

Mr. Coyne captured utility specific risk for FBC in the requested equity ratio of 40.0 percent, while capital market conditions and average business risk are reflected in the recommended ROE of 10.0 percent.

60.0 Reference: Exhibit B1-8-1, Appendix C, pages 54 and 62

Exhibit B1-9, BCUC 27.3.1

Preamble: The response to BCUC 27.3.1 states:

> "Based on these numbers, FBC believes that, holding all else equal, a 44 bps premium to allowed ROE and approximately 2 percent premium to equity ratio would be reasonable to account for the difference between vertically integrated and distribution- only utilities, including those in BC".

60.1 Based on the proxy groups used, do the electric utility results set out in Appendix C (pages 54 and 62) for Mr. Coyne's DCF an CAPM models reflect the values for vertically integrated electric utilities or distribution- only electric utilities?

Response:

Concentric provides the following response:

All of the companies in Mr. Coyne's U.S. Electric proxy group are vertically-integrated electric utilities. The same is not true for his Canadian proxy group, where only Emera and Algonquin Power and Utilities Corp. have operating subsidiaries with significant generation ownership. Mr. Coyne's U.S. Electric proxy group, on which his recommended ROE of 10.0 percent for FBC is based, reflects the return requirements for vertically-integrated electric utilities.

61.0 Reference: Exhibit B1-9, BCUC 38.4

61.1 Please provide historical spreads for Canada and US government 10-year versus 30-year bonds using daily bond yields for the most recent 30 trading days available.

Response:

Please refer to Attachment 61.1. The average spread between 10-year and 30-year government bonds for the 30 trading days ended May 31, 2022 was 14 basis points in the U.S. and minus 3 basis points in Canada.

62.0 Reference: Exhibit B1-9, BCUC 39.1 and 39.5 (Attachment)

Exhibit B1-8-1, Appendix C, Exhibit JMC-FEI-6 & Exhibit JMC-FBC-6

62.1 In response to BCUC 39.1, Concentric explains why it's appropriate to include in the forward-looking MRP calculation non-dividend paying firms and those with growth rates in excess of 20% or less than 0%. However, in the attachment to BCUC 39.5, Concentric has excluded companies with no dividend yield from the calculation (per Exhibit JMC-FEI-6 & Exhibit JMC-FBC-6). Please reconcile and explain why non-dividend paying firms were excluded.

Response:

Concentric provides the following response:

Mr. Coyne excludes non-dividend paying companies in his market risk premium calculation because the DCF model cannot be used on companies that do not pay dividends. Both Mr. Coyne and FERC exclude non-dividend paying companies. Where he differs from FERC is Mr. Coyne includes all dividend paying companies, while FERC excludes those with earnings growth greater than 20% or less than 0%. Mr. Coyne includes all dividend paying companies to better approximate the market return available to investors.

62.2 What would the Canadian and US MRP results be if all companies with long term growth estimates (including non-dividend paying firms) were included in the calculations?

Response:

Concentric provides the following response:

Please refer to Attachment 62.2 for the calculation of the forward-looking MRP in Canada and the U.S. if all companies with long-term growth rates were included. In order to do so, the growth rates for the non-dividend paying companies are included in the calculation, even though dividend yields are unavailable.

62.2.1 How would this impact the calculated ROE values?

Response:

Concentric provides the following response:

Please refer to Attachment 62.2.1.

The table below (which is a revised version of Figure 30 in Mr. Coyne's report) summarizes the CAPM results for the various proxy groups using the forward-looking MRPs shown in Attachment 62.2. These estimates are substantially higher than those used in Mr. Coyne's methodology and recommendations.

	Average MRP	**Forward-looking MRP**
Canadian Utilities	12.27%	15.75%
U.S. Gas Utilities	12.19%	15.51%
North American Gas Utilities	12.68%	16.24%
U.S. Electric Utilities	12.74%	16.26%
North American Electric Utilities	12.37%	15.79%

63.0 Reference: Exhibit B1-9, BCUC 41.9

Exhibit B1-8-1, Appendix C, page 62 (Figure 30)

63.1 In response to BCUC 41.9 Concentric provided the 10-year raw and adjusted betas for each of the proxy groups. Please provide a revised version of Figure 30 based on the 10-year adjusted beta values.

Response:

Concentric provides the following response:

Figure 30 has been revised below to reflect 10-year adjusted beta values from Bloomberg rather than five-year adjusted Beta coefficients. Please refer to Attachment 63.1. These results are lower than those from Mr. Coyne's estimates which relied on the more common 5-year betas, by 0.09% to 0.42%, depending on the proxy group and Average vs. Forward-looking MRP.

Revised Figure 30: CAPM Results Using 10-Year Adj. BB Betas (including flotation costs)

	Average MRP	**Forward-looking MRP**
Canadian Utilities	10.59%	12.44%
U.S. Gas Utilities	10.50%	12.25%
North American Gas Utilities	10.91%	12.80%
U.S. Electric Utilities	10.78%	12.60%
North American Electric Utilities	10.53%	12.31%

64.0 Reference: Exhibit B1-9, BCUC 43.1

Preamble: The response states:

> "In essence, financial flexibility is necessary so that utilities such as FEI and FBC have the ability raise capital under a variety of economic and market conditions, including periods such as the financial crisis of 2008/2009 and the COVID pandemic of 2020- 2022".

64.1 Please explain more fully why an additional allowance needs to be included in the ROE to give FEI and FBC the ability raise capital under a variety of economic and market conditions. Why don't the results of the DCF and CAPM methodologies already provide adequate provision for such circumstances?

<u>Response:</u>

Concentric provides the following response:

The DCF and CAPM models do not include an allowance for financial flexibility. An allowance for financial flexibility is necessary because capital market conditions can become extreme (i.e., high volatility, lack of liquidity), as we have seen in 2022, yet regulated gas and electric utilities such as FEI and FBC still have an obligation under the regulatory compact to provide safe and reliable service to customers and must have the ability to raise both debt and equity capital on reasonable terms regardless of conditions in the economy or capital markets. Please also refer to the responses to BCUC IR2 83.1 and 83.2 for additional information regarding the purpose of an allowance for financial flexibility.

65.0 Reference: Exhibit B1-13, RCIA 29.1

Preamble: The response states:

> "Mr. Coyne's report does not state that the MRP is similar in Canada and the U.S., but rather that because the U.S. and Canadian economies are highly integrated and capital flows freely across the border, the risk premiums for each country are highly correlated. Accordingly, it is reasonable to derive a single forward- looking estimate of the MRP for Canada and the U.S".

65.1 While the MRPs may be correlated, are there reasons (e.g., differences in taxes, etc.) why the two values would not be expected to be the same?

65.1.1 If yes, what are they and (directionally) what impact will they have on the differences?

<u>Response:</u>

Concentric provides the following response:

There are several factors that could cause the equity risk premiums in Canada and the U.S. to deviate, among them are differences in: inflation, interest rates, growth prospects for companies or industry concentrations, fiscal and monetary policies, and tax rates. The direction and degree of impact depends on how wide the gap is, and whether other factors are offsetting the difference. Over time, as indicated in Mr. Coyne's testimony, market returns in the U.S. and Canada have been highly correlated.

Please also refer to the responses to BCUC IR2 84.4 and 84.4.1.

66.0 Reference: Exhibit B1-9, BCOAPO 23.1

66.1 The reason for the original interrogatory was a concern that the COVID- 19 pandemic had unduly influenced the application of the CAPM model by: i) using dividend yields as of December 31, 2021 that may have been unduly high due to the pandemic deceasing market prices and ii) using EPS growth rates determined around December 31, 2021 when current earnings may have been reduced due to the pandemic leading to higher EPS growth rates going forward (assuming recovery in the future). Can Concentric comment on whether or not these two issues and the use of the specific data noted may have unduly impacted and biased the results of the CAPM methodology?

Response:

Concentric provides the following response:

Mr. Coyne assumes that the question is referring to the effect of dividend yields and EPS growth rates used in the DCF model to compute the forward looking MRP for the CAPM model.

Mr. Coyne based his ROE analysis on recent market data and expected market conditions. Stock prices in the U.S. and Canada were near all-time highs in December 2021, and the dividend yields as of December 31, 2021 were below historical average levels. The average dividend yield for dividend paying companies in the S&P 500 was 1.74% compared to 2.32% as of 11/30/19, and the dividend yield for the dividend-paying companies in the S&P/TSX Index was 3.15% compared to 3.45% as of 11/30/19. These lower dividend yields would lower the resulting market return estimate. EPS growth rate estimates were higher than normal in December 2021, but this is not surprising given the extraordinary monetary and fiscal stimulus provided to the economies in both Canada and the U.S. The expected EPS growth rate for dividend paying companies in the S&P 500 was 13.14% as of 12/31/21 compared to 8.92% in 11/30/19, while in Canada the EPS growth rate was 8.40% compared to 7.15% on 11/30/19. Higher EPS growth rates would increase the market return estimate. Taken together, lower dividend yields and higher EPS growth rates would be offsetting factors.

Further, Mr. Coyne's CAPM results are based on the average of the historical and forward-looking MRP in both countries, which further dilutes the effect of current market data on dividend yields and EPS growth rates.

67.0 Reference: Exhibit B1-9, BCOAPO 26.7 and 26.7.1

Preamble: The response states:

> "Beta coefficients from both Value Line and Bloomberg have increased substantially for utilities in both Canada and the U.S. since January 2020".

67.1 Could part of the increase in the beta coefficients since January 2020 be attributed to the COVID-19 pandemic?

67.1.1 If not, why not?

Response:

Concentric provides the following response:

Recognizing that beta is a relative measure – it measures the relationship between utility market returns and overall market returns – COVID-19 would only impact utility betas to the extent investors deem utilities to be affected more than the market overall. More likely, other factors at work are a growing awareness by investors of Energy Transition risks, changes in load patterns and customer consumption levels, and more recently the negative impacts of increasing interest rates and inflation. These more recent factors are blunted, but not eliminated, by using betas measured over a 5-year period, as Mr. Coyne has done in his analysis.

68.0 Reference: Exhibit B1-9, BCUC 13.1.1

Preamble: The response states:

> "From the cost perspective, record inflation is increasing O&M and capital expenditures. FEI's and FBC's O&M expenditures and FEI's growth capital are indexed to a composite inflation factor (minus a productivity factor of 0.5 percent) and are less impacted by high inflation rates. However, FEI's sustainment capital, as well as FBC's sustainment and growth capital expenditures are forecast. Therefore in the short-term, and to the extent actual inflationary pressures experienced by FEI and FBC in these categories are higher than what was previously forecast, FEI and FBC are at risk of not being able to recover their costs above their initial forecast until the next rebasing".

68.1 Do the earnings sharing mechanisms included in FEI's and FBC's PBR plans provide some opportunity for relief and partial recovery of costs above initial forecast level prior to the next rebasing?

<u>Response:</u>

The earnings sharing mechanism (ESM) is a safeguard mechanism designed to protect both the utility and ratepayers from windfall losses or earnings. Under the currently approved MRP framework[5], the ESM is applied to the overall earnings and not individual cost categories. Cost variances are only one factor in the earnings calculation and therefore the impact of higher actual costs compared to forecast could potentially be offset by other factors that may positively impact earnings. Nevertheless, it is true that if the cost overruns result in an achieved ROE that is below the approved ROE, then the ESM can mitigate some of the additional risk typically associated with PBR versus cost of service regulation.

[5] Approved by Orders G-165-20 and G-166-20.

69.0 Reference: Exhibit B1-9, BCUC 13.3.3

Preamble: The response states:

> "In addition, Standard and Poor's ("S&P") recently reported that the median credit rating for regulated utilities dropped to BBB for the first time ever".

> "For the second consecutive year rating downgrades outpaced upgrades for the investor-owned North American regulated utility industry, causing the median rating on the industry to fall to the 'BBB' category".

69.1 Overall, since 2020 for companies making up the S&P 500 and/or the S&P/TSX Composite have rating downgrades exceeded rating upgrades or vice versa?

<u>Response:</u>

Concentric provides the following response:

The following response and Attachment 69.1 are 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, this response and Attachment 69.1 are 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.

[redacted]

[redacted]

[redacted]

70.0 Reference: Exhibit B1-9, BCUC 14.3

Exhibit B1-8-1, Appendix C, page 81

Preamble: The response to BCUC 14.3 states:

> "All of this evidence demonstrates that investors are assigning a higher risk premium to companies with higher carbon emissions, and that certain large investors are restricted from investing in such companies, which thereby limits the pool of available capital. Additionally, the Betas for both gas and electric utilities have increased substantially (see Figure 28 p. 58 of Mr. Coyne's report), indicating that investors are seeing utilities as riskier than they have previously".

70.1 With respect to the S&P graphic on page 81, into which "quartile" would FEI fall?

Response:

Concentric provides the following response:

The Figure 41 on page 81 of Mr. Coyne's evidence is prepared by S&P for a group of North American energy companies. In this study, S&P grouped the companies into quartiles based on the carbon intensity of their revenues as calculated by Trucost.[6] Mr. Coyne does not have access to the necessary data used in the grouping of these companies into quartiles and as such is unable to determine in which quartile FEI would have been placed. The Figure 41 is provided for illustrative purposes to demonstrate the impact of ESG factors on debt financing and clearly shows that Issuers in the highest carbon intensity quartile tend to have materially more expensive debt than issuers in the lowest carbon intensity quartile.

70.2 How has the average of the Value Line Betas based on all of the companies assessed by the firm changed since January 2020?

Response:

Concentric provides the following response:

As of June 3, 2022, the median beta for all companies covered by Value Line, which number approximately 4,600, is 1.05. Please refer to Attachment 70.2. Historical Value Line data is not generally accessible through our subscription, so Mr. Coyne cannot compare to the average

6 Trucost is part of S&P Global

Value Line beta at January 2020. Please refer to the response to BCOAPO IR2 70.3 for an indication of the change measured using Bloomberg.

70.3 How has the average of the Bloomberg Betas based on all of the companies assessed by the firm changed since January 2020?

Response:

Concentric provides the following response:

Bloomberg covers a very large number of equities for which gathering all the betas is not generally possible. However, analyzing a representative subset of the Bloomberg equity universe is possible. For example, the median five-year Bloomberg adjusted beta on June 3, 2022, of the approximately 4,600 Value Line-covered equities (refer to the response to BCOAPO IR2 70.2) is 1.03. For comparison, the median five-year Bloomberg beta for this same group of companies on January 1, 2020, was 0.96. Please refer to Attachment 70.3.

71.0 Reference: Exhibit B1-9, BCUC 19.2

Preamble: The response lists a number of operating risks that FEI claims are increasing including:

- Infrastructure and time-dependent threats;
- Third-party damage;
- System resiliency risks, as illustrated by the Westcoast T- South pipeline rupture;
- Extreme weather events that are impacting FEI's operations; and

71.1 Please provide evidence that the operating risks associated with each of the factors listed in the preamble are increasing and have increased since 2016.

Response:

The citation in the preamble from BCUC IR1 19.2 is taken from the context of the various factors that impact the need for transmission and distribution asset replacement; not overall operating risk. FEI discusses each of the four factors below.

Infrastructure and Time-dependent Threats

FEI's submission in Appendix A – FEI Business Assessment Risk: Stage 1 Evidence explained that infrastructure and time-dependent threats and third-party damage risks, as they impact overall operating risk, remain consistent with the level of risk presented in the 2016 Proceeding. Aging assets and time dependent threats increase the risk of asset failure resulting from corrosion and cracking, known to exist on some of FEI's assets. FEI's risk of aging infrastructure and time dependent asset failure remains similar to that of the 2016 Proceeding.

Third-party Damage

FEI experienced 1,034 incidents in 2021 which is close to the number of third party damages experienced in 2016. FEI continually improves the damage prevention program to maintain the current risk level which is consistent with the level at the time of the 2016 Proceeding.

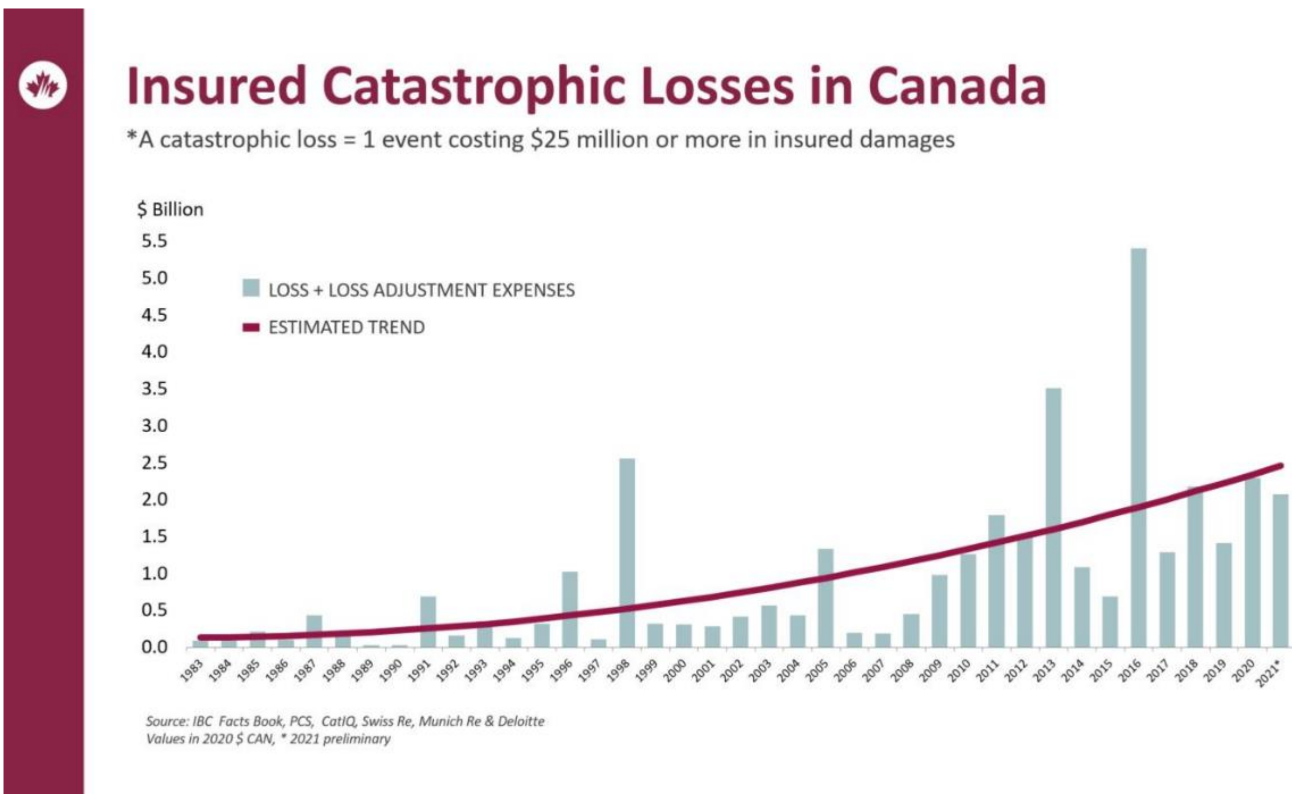
System Resiliency and Extreme Weather Events

System resiliency refers to the ability to prevent, withstand and recover from system failures or unforeseen events which would include the impact of extreme weather events. Recent evidence supports that the operating risks associated with system resiliency and extreme weather events as listed in the pre-amble above, as well as in FEI's submission in Appendix A, are increasing and have increased since 2016. This is demonstrated by the following examples.

- The Westcoast T-South pipeline operated for many years without major interruption up until 2018 when a rupture occurred on the pipeline.

- In addition to the 2018 rupture, the T-South line was recently curtailed as part of the flood response to pipelines serving the Lower Mainland during the extreme weather events in Fall 2021. The flooding of an adjacent river exposed a portion of Westcoast's 30-inch line 32 such that a section was fully uncovered in the overflowing river.
- Extreme weather events in recent years have also directly impacted FEI's operations. The recent flooding in the Fraser Valley, Merritt, Princeton and Abbotsford, resulted in the loss of natural gas service to 1,700 customers. The resulting damage to FEI's system for this event is approximately $3 million.

In addition, the impact of extreme weather events and their increased occurrence is a general phenomenon being observed across Canada as evidenced by the amount of insured catastrophic losses. The following graph demonstrates the loss, loss adjustment expenses, and estimated trend insurance companies are seeing in Canada from extreme weather events since the 1980s.



72.0 Reference: Exhibit B1-9, BCUC 50.1

Preamble: The response states:

"It is difficult to reach any general conclusion regarding utility regulation in the U.S. and Canada. Mr. Coyne views the regulatory environments as being similar in both countries".

72.1 Has Mr. Coyne done any comparative analysis of the BC regulatory environment as compared to the regulatory environment faced by the specific Canadian and US utilities included in his various proxy groups?

72.1.1 If yes, what were the results?

Response:

Concentric provides the following response:

Yes. Please see pages 104-105 of Mr. Coyne's report for a discussion of how credit rating agencies (i.e., S&P) and equity investors (i.e., UBS) perceive the regulatory environment in BC compared to other Canadian provinces and U.S. states. In summary, the regulatory environment in BC is generally viewed as favorable from an investment perspective. Also, please see pages 115-117 of Mr. Coyne's report for a comparison of the regulatory risk of FEI relative to the U.S. Gas proxy group, and pages 139-141 for the same comparison of FBC to the U.S. Electric proxy group.

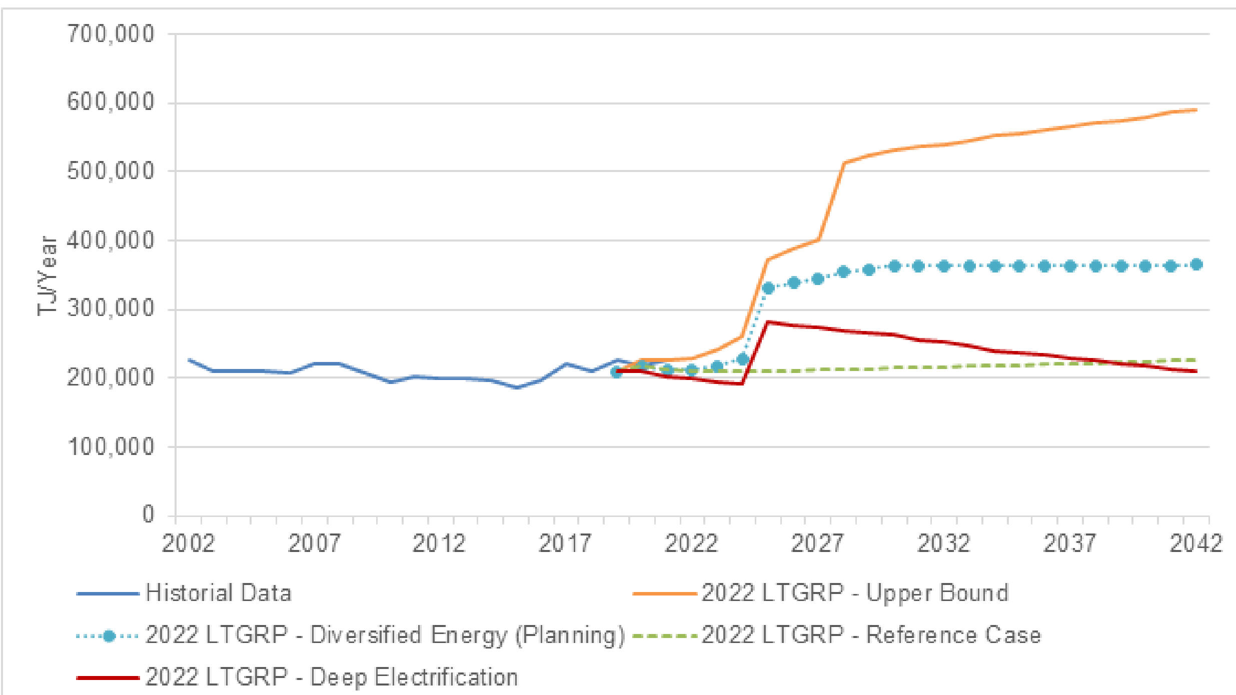
73.0 Reference: Exhibit B1-13, RCIA 3.6 and 3.7

73.1 Based on FEI's recently filed 2022 Long Term Gas Resource Plan please provide a schedule that sets out both FEI's historical sales (per RCIA 3.6) and its forecast sales to 2041.

Response:

Please refer to Figure 1 below showing the historical gas sales (TJ) from 2002 to 2021 as provided in RCIA IR1 3.6 along with the forecasts of future gas sales from FEI's 2022 Long Term Gas Resource Plan (LTGRP). As discussed in the 2022 LTGRP, FEI's future demand will depend on a variety of factors resulting in different demand scenarios. For comparison of the different scenarios, FEI included the Reference Case, the Diversified Energy Planning, Deep Electrification, and Upper Bound scenarios in Figure 1 below. FEI believes these four scenarios from the 2022 LTGRP represent the likely range of future demand for FEI to 2041. Please refer to Section 4 of FEI's 2022 LTGRP for detailed discussion of the different demand scenarios.

Figure 1: FEI Historic and Forecast Gas Demand (Sales)



Notes:

- The overlap from 2020 to 2022 in Figure 1 above is due to FEI's 2022 LTGRP being developed using 2019 actuals as the base year with 2020 to 2022 as forecast while the historical data from RCIA IR1 3.6 had actual gas sales in those years as well; and
- The demand forecasts shown under the Diversified Energy Planning, Deep Electrification, and Upper Bound scenarios from FEI's 2022 LTGRP include the demand from the Woodfibre LNG

project (seen as the sharp increase in the demand line in each of those scenarios). See Section 4.7 of FEI's 2022 LTGRP.

74.0 Reference: Exhibit B1-13, RCIA 15.1.1

Preamble: The response states:

"As explained in FortisBC's evidence, in its 2009 decision, the BCUC increased FEI's cost of capital to reflect, among other things, the introduction of climate change legislation by the provincial government and the scenarios in the Nyboer Report highlighting the long-term Energy Transition risk to FEI".

74.1 How do the future gas demand scenarios in the Nyboer Report compare to the scenarios for FEI's future gas demand as set in its recently filed 2022 Long Term Gas Resource Plan?

Response:

As described below, given the nature of Nyboer report, it is impossible to perform a meaningful comparison between FEI's LTGRP and the demand forecasts presented in the report.

For context, Nyboer's report titled "A technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: a sectoral and regional analysis" published in August of 2008 first arose in the FEI (then Terasen Gas Inc. or TGI) 2009 cost of capital proceeding by way of a BCUC Panel IR towards the end of the proceeding. In response to the BCUC question about the report, TGI filed the report and characterized its relevance as follows:[7]

> Reports of this type to policy makers, with access by consumers, can and does shape the long-term view of policy makers and the broader community respecting a product (in this case, natural gas) and may well be influential in formulating public policy that has long-term negative impacts on the demand for that product (i.e. natural gas). The outcome identified in the Report would reduce throughput on the Terasen natural gas delivery systems, which all else equal, will increase the unit costs to the remaining natural gas customers. In the extreme, the Company could have stranded assets if the roadmap that is outlined in the Report materializes.

In other words, the discussion around the Nyboer report in the context of TGI's business risk, was focused on the potential for reports like this one to influence government policy in a manner that would be unfavourable to TGI. TGI did not evaluate or highlight demand forecasts in the Nyboer report, which the report acknowledged were "highly uncertain, in part because there are often multiple methods of reducing greenhouse gas emissions from a specific sector".

This is consistent with TGI's President's comments in the 2009 cost of capital proceeding oral hearing where he stated that the main concern with these type of reports is the "degree of

[7] Exhibit B-11 in 2009 cost of capital proceeding; BCUC IR No.1

influence it seems to be having in certain circles amongst policy makers."[8] The focus on policy is also evident from BCUC statement in the 2009 proceeding[9]:

> The Commission Panel agrees with Terasen that the introduction of climate change legislation by the provincial government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity. In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. <u>The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers</u>. [Underline added]

Given the nature of Nyboer report, it was and remains impossible to perform a meaningful comparison between FEI's demand forecasts / LGTRP and the Nyboer report demand forecasts. This is primarily because:

- The total demand forecasts in Nyboer's report represent the total demand in the entire province, while FEI's demand forecast scenarios only focus on FEI's customers' consumption; and
- Nyboer's report considers both upstream use (the oil and gas industry's own on-site demand and not included in FEI's demand – referred to in the Nyboer report as 'supply-side') and the down-stream demand (referred to in the Nyboer report as demand-side).However, the report does not specify how much of the forecast natural gas demand relates to the upstream use and how much relates to the downstream use (residential, commercial, industrial, transportation that is included in FEI's demand). The lack of specificity makes it impossible to compare the forecasts at a more meaningful customer segment level.

The CIMS model used to forecast the energy demand scenarios discussed in the Nyboer report appears to have been developed to explore specific pathways to reach a desired outcome with respect to energy use and GHG emissions and thereby influence energy and climate policy. In contrast, the annual demand forecasting model employed for FEI's 2022 LTGRP is designed to examine how different actions taken by customers with respect to their energy end uses will impact FEI's total future demand and is based on energy use data from FEI's own customers and supply resources. The LTGRP modelling objective is to serve as a foundation for further evaluation of gas supply/demand and system infrastructure options for meeting customer needs under different future planning environment scenarios.

8 2009 cost of capital proceeding; Oral Hearing (T3:279-80).
9 2009 cost of capital decision, p. 37.

The Nyboer report illustrates how far climate ambition and the policy framework have advanced since 2009. While many of the general policy changes envisioned by the Nyboer report are now being implemented, both climate targets and the stringency of policies has increased significantly since the report was published. For example, the report creates a roadmap to achieve a 65 percent reduction in emissions by 2050 whereas both federal and provincial climate targets exceed the targets which the Nyboer report is based upon. The federal government has adopted a target to achieve net zero emissions by 2050. BC's legislated target remains at an 80 percent reduction in emissions by 2050; however, the provincial government has highlighted its ambition towards net zero in the CleanBC Roadmap to 2030.

75.0 Reference: Exhibit B1-11, CEC 22.2 and 22.4

Exhibit B1-13, RCIA 3.2

Preamble: The response to CEC 22.2 states:

> "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".

The response to CEC 22.4 states:

> "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".

The response to RCIA 3.2 states:

> "The CER, in its most recent scenario analysis and projections contained in its Canada's Energy Future 2021 report, released February 9, 2022, projects total end-use natural gas demand in British Columbia to decline from 416.9 Pj in 2021 to 386.1 in 2030 and 326.9 in 2050.2 This represents an aggregate decline in demand of over 20%. This case is the Evolving Policies Case for British Columbia".

75.1 Please set out the results of the various demand scenarios used in FEI's recently filed 2022 Long Term Gas Resource Plan and identify which of scenarios FEI is using as its "planning scenario".

<u>Response:</u>

Figure 4-20 below, reproduced from FEI's 2022 LTGRP, shows the various total annual gas demand scenario results as requested. For the purposes of the 2022 LTGRP, the Diversified Energy Scenario is FEI's planning scenario. These results should be considered in the context of Section 4 of the 2022 LTGRP. Total annual gas demand in these results include demand from residential, commercial and industrial customers, demand for gas as a transportation fuel and forecasted demand for global LNG that could be supported by FEI's infrastructure and for potential new large industrial demand such as the Woodfibre LNG export facility.

Figure 4-20: Total Annual Demand Including LCT – All Categories, All Scenarios

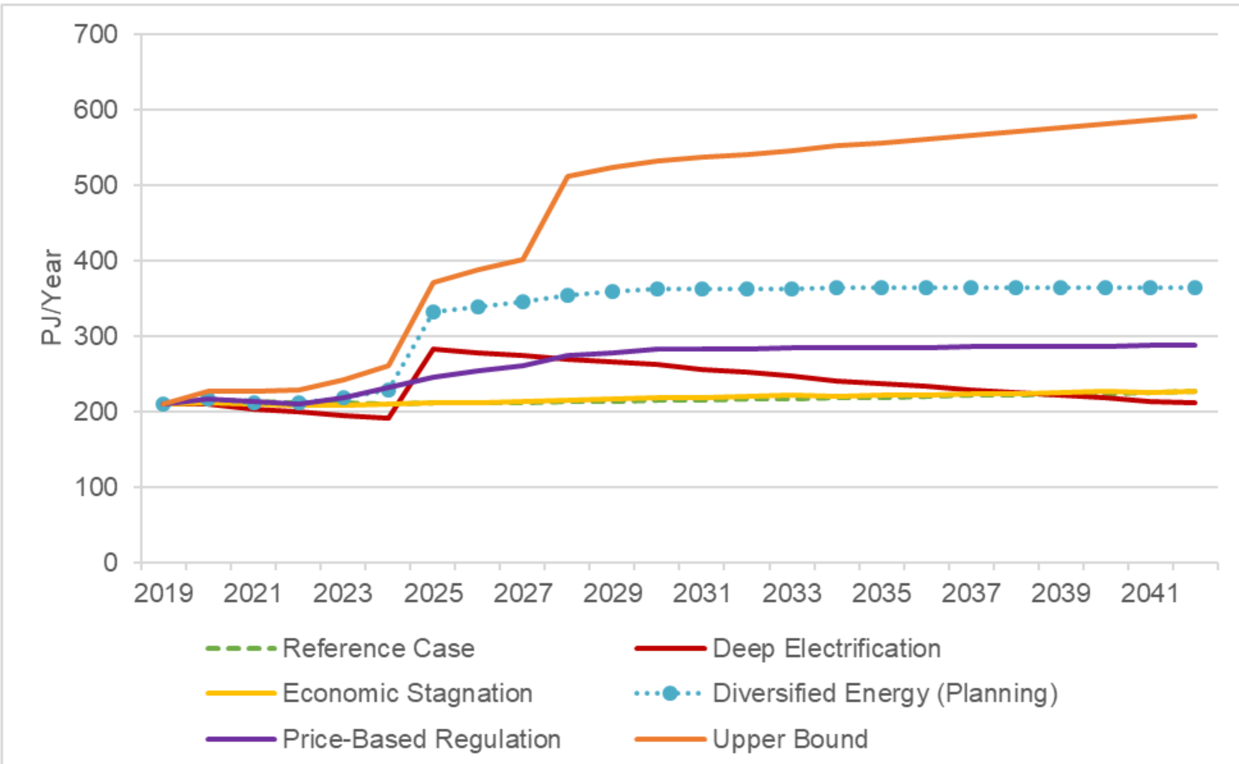
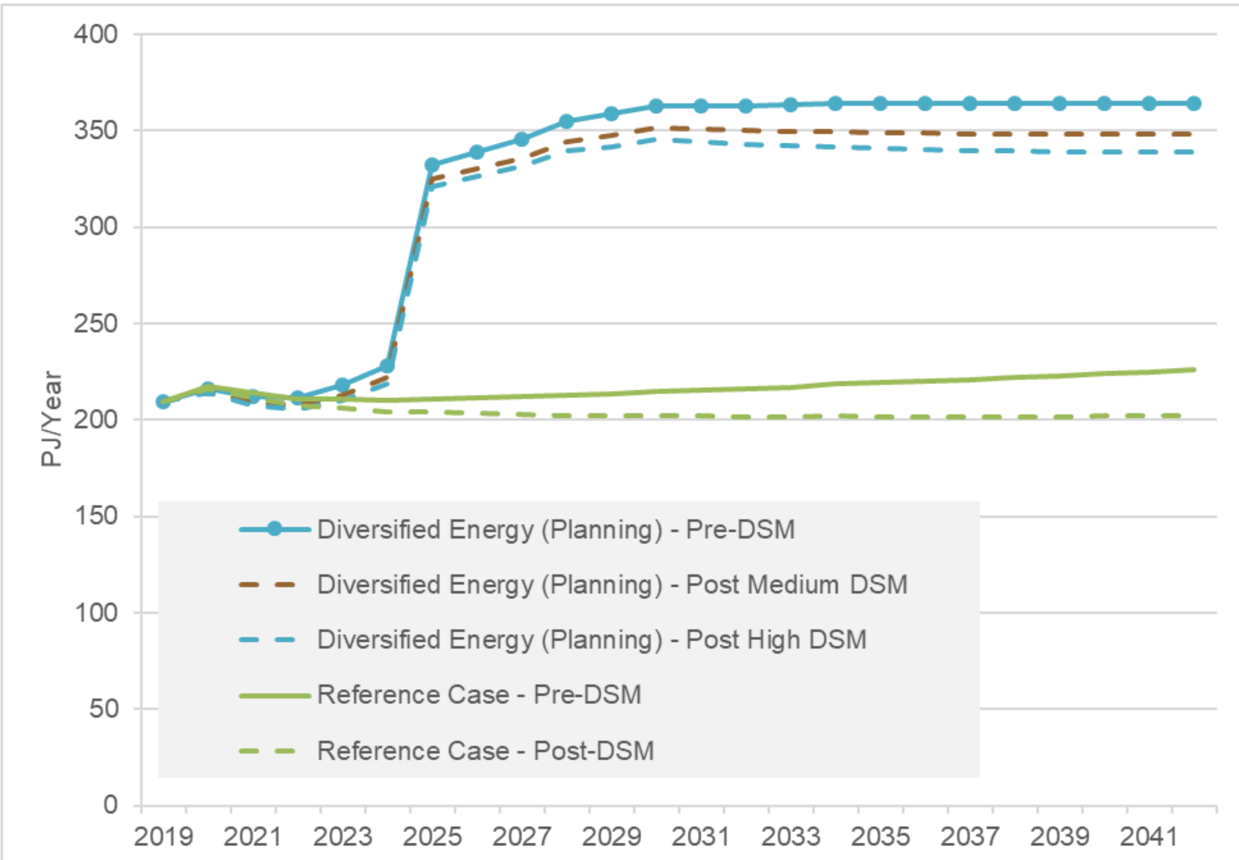


Figure 5-13 below, also reproduced from FEI's 2022 LTGRP, shows the annual demand forecast for the Diversified Energy Scenario before and after estimated energy savings from DSM. The results of modelling both the high and medium levels of DSM expenditure are included in Figure 5-13 along with, for comparison, the results of the reference case annual demand forecast and DSM savings. These results should be considered within the context of Section 5 of the LTGRP. FEI notes the large increase in the Diversified Energy Scenario is due to the addition of the Woodfibre LNG load.

Figure 5-13: Total Annual Demand After DSM - Including LCT

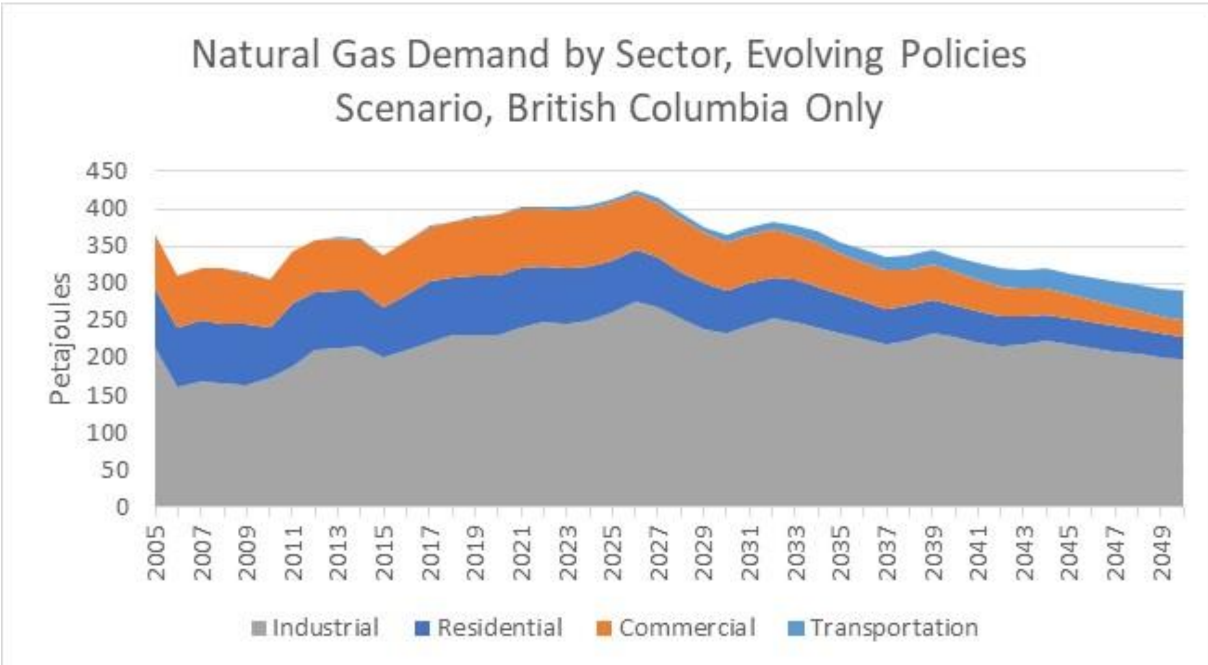


75.2 With respect to the response to CEC 22.4, please provide the equivalent of Figure ES.14 from the CER report for the province of BC.

<u>Response:</u>

Concentric provides the following response:

Although it is not possible to recreate the exact equivalent of ES.14 for British Columbia, Mr. Coyne found data on the CER website that he used to develop the graph below. Please refer to Attachment 75.2 for the underlying data.



75.3 How do FEI's scenarios in its 2022 Long Term Gas Resource Plan compare to the natural gas demand forecast for BC prepared by CER in its Canada's Energy Future 2021 report?

<u>Response:</u>

In preparing the response for this question, FEI identified that it had reported the wrong projected demand numbers in the response to RCIA IR1 3.2. Specifically, the CER projected demand numbers provided in the response to RCIA IR1 3.2 are for "*primary energy*" demand and not the *end-use* demand. According to CER's Energy Future Report[10], the total *end-use* natural gas demand in BC is projected to decline from 403 PJ in 2021 to 365 PJ in 2030 and 290 PJ in 2050 which represents an aggregate decline in end-use demand of approximately 28 percent.

FEI's LTGRP total annual demand forecast scenarios cannot be readily compared with CER's natural gas demand forecast for BC in its 2021 Canada's Energy Future report since the demand forecasts in CER's report represent the total demand in the entire province while FEI's demand forecast scenarios are only focused on FEI's customers' consumption. Nevertheless, examining

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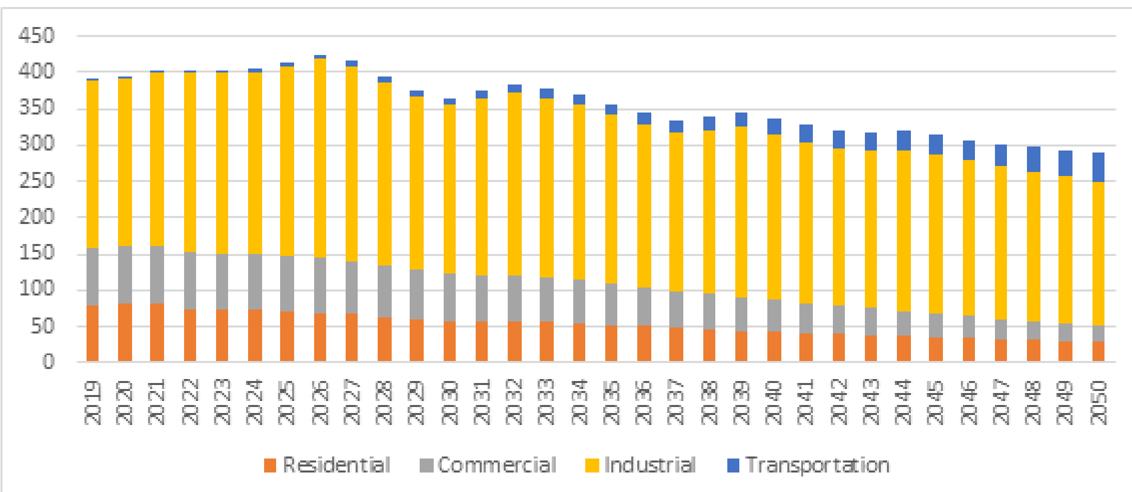
[10] End - Use Demand - Canada.ca (cer-rec.gc.ca)

the various segments of end-use demand in the CER report, such as residential end-use demand, can provide some insight.

Figure 1 below demonstrates CER's end-use natural gas demand projections by customer type. As shown, CER projects that the residential and commercial end-use demand would decline significantly from 81 PJ and 79 PJ in 2021 to 41 PJ and 42 PJ in 2041 and 30 PJ to 22 PJ in 2050 respectively. The industrial load will be more stable although it is projected to decrease from 240 PJ is 2021 to 221 PJ in 2041 and 198 PJ in 2050. The transportation sector is the only sector that would experience an increase in annual natural gas demand, increasing from 2 PJ in 2021 to 23 PJ in 2041 and 40 PJ in 2050.

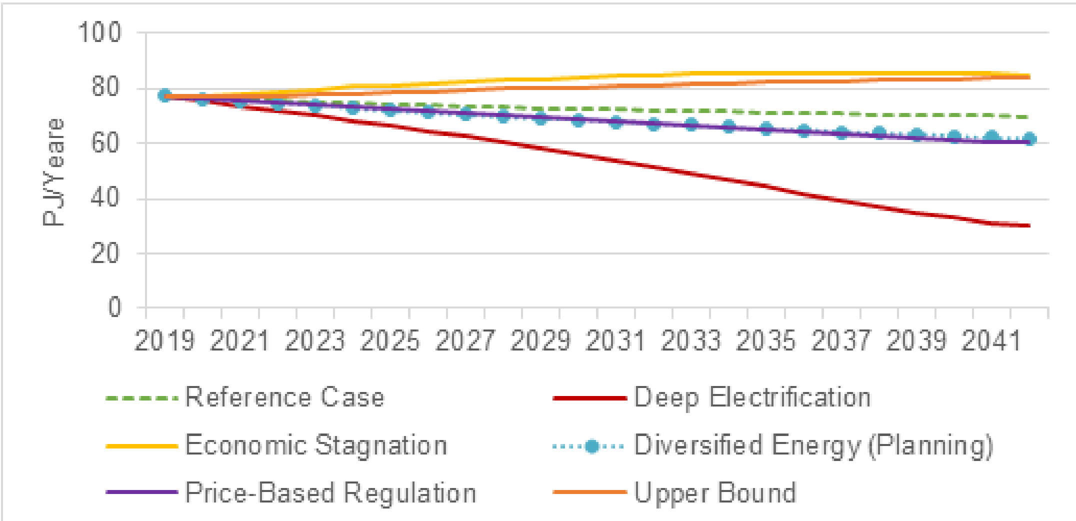
Figure 1: CER's long-term Natural Gas End-use Demand Forecast by Customer Segment



The following discussions should be considered within the context of Sections 4 and 5 of the LTGRP.

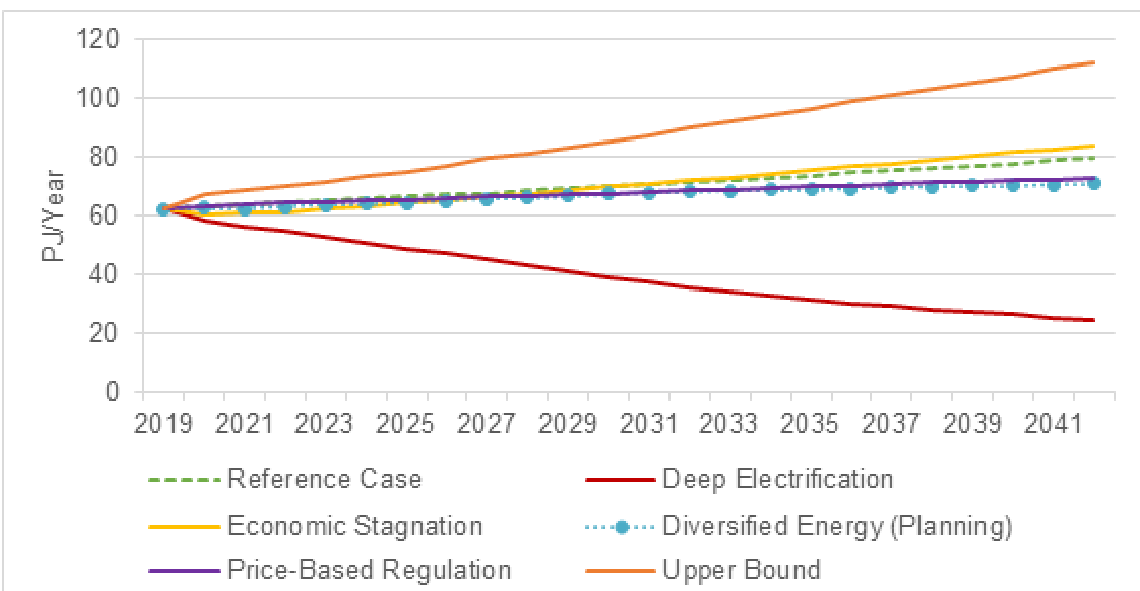
FEI's residential customers represent the majority of the residential gas consumption in the province and as such the comparison of residential demand forecast in CER's and FEI's LTGRP models is the most meaningful. As shown in the Figure 1 above, CER forecasts that by 2041, residential annual gas demand in BC will decrease to 41 PJ. This resulting estimate lies between FEI's residential demand projections under the "deep electrification" (DE) scenario and the "Diversified Energy Planning" (DEP) Scenario shown in the Figure 2 below. The 2041 residential annual demand forecast in the DEP scenario, post DSM using the high DSM setting, is around 54 PJ which is higher than the CER projection.

Figure 2: FEI's Annual Demand Scenarios – Residential



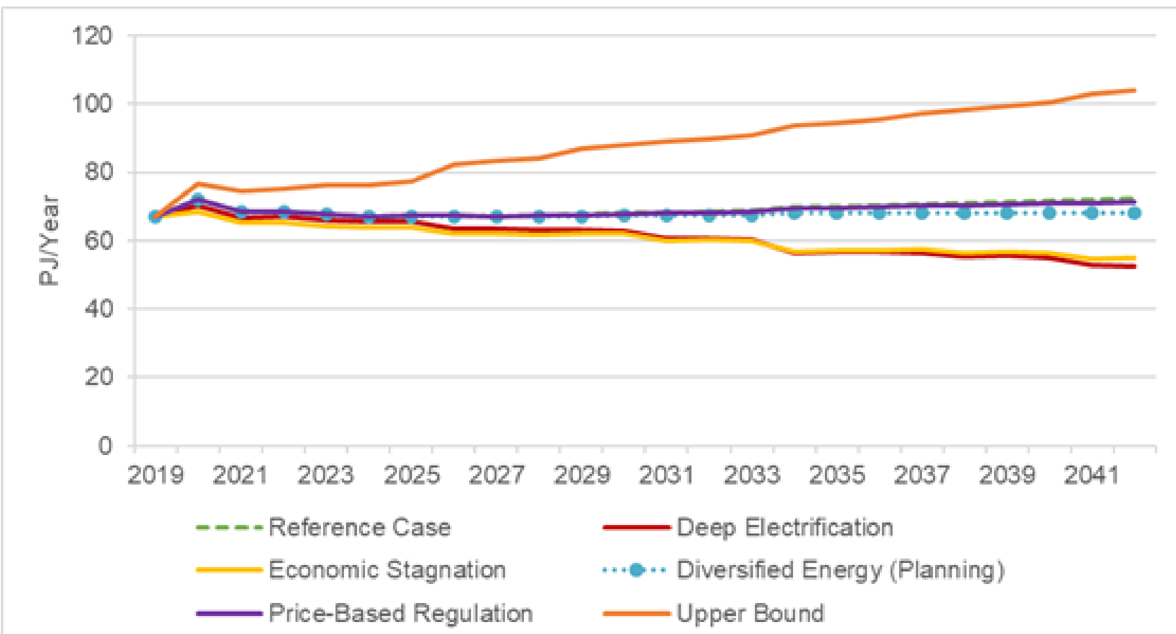
Although not to the same extent as residential customers, FEI's commercial customers represent the majority of the residential gas consumption in the province and as such the comparison of commercial demand forecast in CER's and FEI's LTGRP models is reasonable. CER forecasts that by 2041 commercial annual gas demand in BC will decrease to 42 PJ. This result lies between FEI's commercial end-use demand projections under the DE and DEP scenarios shown in the Figure 3 below. The 2041 commercial demand forecast post-DSM in the DEP scenario under the high DSM setting is around 60 PJ which is higher than the CER projection.

Figure 3: FEI's Annual Demand Scenarios – Commercial



Under FEI's scenario analysis, electrification of the industrial sector over the planning horizon is modelled to be less than that of the residential and commercial sectors on a percentage basis as it is assumed that some industrial end uses will be too difficult to electrify in that time frame. This is consistent with CER's modelling which forecasts that by 2041, industrial annual gas demand in BC will decrease to 221 PJ which is only 19 PJ lower than the 2021 forecast. As expected, FEI's current industrial load and also its industrial load forecasts under all scenarios is considerably lower than the CER's forecast. This is mainly due to the fact that CER's forecasts consider the demand in the entire province. FEI's 2041 industrial demand forecast in the DEP scenario, post-DSM using the high DSM setting is approximately 62 PJ, significantly lower than the CER projection.

Figure 4: FEI's Annual Demand Scenarios – Industrial



76.0 Reference: Exhibit B1-11, CEC 39.1

Preamble: The response states:

> "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".

76.1 Would FEI consider the BCUC's recent approval of FBC's proposal to set its EV charging rate based on a levelized cost of service over a number of years as being an example of the type flexibility required in the future regarding cost recovery approaches?

Response:

Yes, the recognition that a project or program may recover its costs when considered over a longer time frame than typically examined as part of an approval process is one type of flexibility that may support the offering of innovative programs by FEI.

77.0 Reference: Exhibit B1-11, CEC 39.5

Preamble: The response states:

> "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."

77.1 Apart from lack of regulatory approval, what else would impact FEI's ability to proceed with system capacity upgrades and similar resiliency projects?

77.1.1 To the extent there are additional factors, have any of these factors actually preventing FEI from proceeding with such projects increased since 2016?

Response:

In addition to the lack of regulatory approvals, other factors such as public opposition to the fossil-fuel based projects can also negatively impact FEI's ability to proceed with these projects. As explained in the Section 9 of FEI's business risk evidence, protests and environmental activism are becoming more frequent. FEI is seeing increased resistance to new projects which is leading to higher risks to execute projects on time at the lowest reasonable cost and can potentially threaten safe and reliable energy delivery to customers. Further, increased municipal requirements and restrictions may create project and schedule uncertainty for FEI.

FEI notes that "regulatory approval" extends beyond the project approval from the BCUC (i.e., the issuance of a CPCN). Many of FEI's projects also require it to seek consent and/or receive approval from other provincial and federal regulatory bodies (e.g., the BCOGC and Fisheries and Oceans Canada, respectively), other stakeholders (e.g., municipalities and regional districts), and Indigenous groups. Each of these entities and groups have the ability to influence the successful and timely completion of FEI's projects.

Please refer to the response to BCOAPO IR2 79.1 for project delays due to regulatory approvals. In addition, as FEI's submission in Appendix A – FEI Business Assessment Risk: Stage 1 Evidence Section 10.1.2, explains, due to increasing regulatory complexity there is a higher uncertainty of whether FEI will be able to complete projects on their needed timeline, or to receive necessary approvals at all.

78.0 Reference: Exhibit B1-11, CEC 40.1, Attachment 40.1

78.1 For FEI, given the range of elapsed time values for both the 2010-2015 and 2016-2020 periods, are the resulting averages of 7.9 months and 10.3 months significantly different (statistically)?

Response:

The IR referenced by this question (i.e., CEC IR1 40.1) was asking FortisBC to provide specific, quantifiable evidence that there has been an increase in regulatory lag over the last five years, which FortisBC demonstrated in Attachment 40.1 to that IR. As shown in Attachment 40.1, there has been an observable increase in the number of days/months from when an application is filed to when a BCUC decision is issued over the last five years (i.e., an increase of 72 days or approximately 2 months for FEI and increase of 23 days or approximately 1 month for FBC). FortisBC considers these increases to the regulatory process to be notable but cannot comment on whether such an increase would be considered "statistically significant" as there are a number of variables which would need to be considered, such as the comparative degree of complexity of each of the applications in each time period and the expected versus actual proceeding length for each application.

78.2 For FBC, given the range of elapsed time values for both the 2010-2015 and 2016-2020 periods, are the resulting averages of 11.6 months and 12.4 months significantly different (statistically)?

Response:

Please refer to the response to BCOAPO IR2 78.1.

78.3 It is noted that for both FEI and FBC the 2010-2015 and 2016-2020 periods include a variety of applications of different types (annual rate approvals, CPCNs, discrete rate approvals, etc.). For similar types of applications, has there been an increase in regulatory lag over the past 5 years?

Response:

For the purposes of responding to this IR, FortisBC used the information provided in Attachment 40.1 to CEC IR1 40.1 and isolated only CPCN applications for each of FEI and FBC. FortisBC chose CPCN applications as the comparator as the number of CPCNs filed in the two time periods was the same and, compared to other types of applications such as revenue requirement applications, the regulatory process for each application was relatively consistent. Additionally, FortisBC removed the CPCNs related to Thermal Energy Services (TES) applications as these types of applications were no longer applicable to FEI after the Alternative Energy Services (AES) Inquiry and the creation of FortisBC Alternative Energy Services Inc. (FAES).

For FEI, there were three CPCN applications in each of the periods from 2010-2015 and 2016-2021. As shown in the FEI tab in the attachment to this IR (Attachment 78.3), there has been an increase in regulatory lag for CPCNs for FEI by approximately six months. For FBC, there were also three CPCN applications in each of the periods from 2010-2015 and 2016-2021. As shown in the FBC tab in Attachment 78.3, there has been no change to the regulatory lag for CPCNs for FBC.

79.0 Reference: Exhibit B1-10, BCOAPO 10.3 and 10.3.1

79.1 In any of the examples cited, has the regulatory delay led to FEI not meeting required in-service or project completion dates such that the provision of reliable service to customers was negatively impacted/affected?

Response:

Both the IGU and LMIPSU projects (the two specific project examples cited in the response to BCOAPO IR1 10.3) did experience regulatory delay (and in the case of the LMIPSU, a delayed project completion date). FEI does not believe that the delays resulted in direct impacts to customer service (although longer project timetables will affect area residents, many of whom are also FEI customers); however, the projects illustrate the increased complexity associated with regulatory approval that is impacting all FEI projects, and hence broadly contributing to regulatory lag.

80.0 Reference: Exhibit B1-9, BCUC 6.2.1 and 7.1

80.1 Please provide the history of FEI's credit rating from 2009 to present.

Response:

Please refer to the following 3 tables for FEI's credit rating history from 2009 to present.

Table 1: DBRS – Unsecured, Secured* and Issuer Rating

Rating Agency	Report Date	Rating Action	Rating
DBRS	Since 2009	Ongoing	A (stable outlook)

**The rating for Secured Debentures was discontinued in 2016 when FEI repaid its secured debentures.*

Table 2: Moody's - Unsecured Debentures

Rating Agency	Report Date	Rating Action	Rating
Moody's	June 2013	Outlook Change	A3 (negative outlook)
Moody's	July 2014	Outlook Change	A3 (stable outlook)

Table 3: Moody's - Secured Debentures*

Rating Agency	Report Date	Rating Action	Rating
Moody's	August 2009	Upgraded	A1
Moody's	June 2013	Outlook Change	A1 (negative outlook)
Moody's	July 2014	Outlook Change	A1 (stable outlook)

**The rating for Secured Debentures was discontinued in 2016 when FEI repaid its secured debentures.*

80.2 Did FEI's credit rating change as a result of its 2015 financial results, particularly the decrease in CFO pre-WC / Debt to 8.4%?

Response:

FEI's credit rating did not change in 2015 when CFO pre-WC/Debt decreased to 8.4 percent because the decrease was expected to be temporary. The following year, this metric was restored to 13.5 percent and stayed above this level until 2020 when the metric decreased to 11.3 percent. Moody's has not completed its 2021 credit rating review and so 2021 is not included in the table below. As noted in Moody's reports, it is the sustained deterioration in credit metrics including CFO pre-WC to debt of less than 11 percent or an adverse regulatory decision that could lead to a rating downgrade. Other reasons that could potentially lead to a credit rating downgrade in the future are ESG risks as highlighted in the response to BCUC IR1 8.1. Credit metric changes of a temporary nature are not expected to lead to a rating downgrade.

	2015	2016	2017	2018	2019	2020
CFO Pre-WC/Debt	8.4%	13.5%	15.5%	13.6%	13.6%	11.3%

81.0 Reference: Exhibit B1-9, BCUC 7.5

Preamble: The response states:

> "Overall, with an exception of the first several months of the COVID-19 pandemic where there was significant uncertainty and access to debt capital markets was limited, the COVID-19 pandemic has had limited impact on FortisBC's liquidity and credit metrics".

81.1 Can either FEI-FBC or Mr. Coyne comment on whether the same observation holds for other Canadian utilities (e.g. those in Mr. Coyne's proxy group) or US utilities (e.g. those in Mr. Coyne's proxy group)?

<u>Response:</u>

Concentric provides the following response:

Concentric has not researched this issue independently but is aware of research provided by Florida Power & Light Company in its 2021 rate case. The company witness, Robert Barrett, Vice President of Finance, provided this information provided to the company by its banks, addressing some of the challenges faced by even highly rated companies in raising debt capital during the early stages of the COVID -19 pandemic. According to witness Barrett:

> During March through April 2020, the capital markets experienced its peak disruption and volatility resulting from the COVID-19 uncertainty. Several lower rated utilities and non-financial corporates attempted to raise debt financing amid these challenging capital market dynamics and were ultimately faced with the difficult decisions of either canceling their publicly announced issuances shortly after launching the prospective transactions or accepting very expensive pricing terms because of limited or insufficient investor interest or demand. For example, during the peak market disruption of the COVID-19 pandemic, of the investment-grade ("IG") rated utility, power company and non-financial corporate debt issuers that launched debt issuances in the capital markets, Table 1 below presents a sample of publicly announced issuances that were subsequently canceled following the launch of the transaction. Importantly, this list of unsuccessful or failed prospective issuances is a subset of what is likely a much larger population of unsuccessful issuances when including those planned transactions that the issuer elected to cancel prior to announcement because of the constrained capital markets.

Table 1. Failed IG-Rated Utility, Power Company and Non-Financial Corporate Debt Issuances During the COVID-19 Pandemic Market Disruption

Date	Issuer	Type	Targeted Amount ($ MM)	Expected Ratings (Moody's/S&P)	Term	Initial Price Talks (bps)
3/17/20	Entergy Corp	Unsecured	benchmark	Baa2/BBB	5-year	+275.0 bps
3/17/20	Entergy Corp	Unsecured	benchmark	Baa2/BBB	10-year	+287.5 bps
3/20/20	EOG Resources	Unsecured	benchmark	A3/A-	7-year	+425.0 bps
3/20/20	EOG Resources	Unsecured	benchmark	A3/A-	10-year	+425.0 bps
3/20/20	EOG Resources	Unsecured	benchmark	A3/A-	20-year	+425.0 bps
3/20/20	Appalachian Power	Unsecured	350	Baa1/ A-	10-year	+337.5 bps
4/6/20	Hewlett Packard	Unsecured	benchmark	Baa2/BBB	7-year	+475.0 bps
4/23/20	Marathon Petroleum	Unsecured	benchmark	Baa2/BBB	10-year	+500.0 bps
4/28/20	DuPont de Nemours	Unsecured	benchmark	Baa1/BBB+	3-year	L equivalent

Table 2 includes those issuances that priced, albeit at very expensive terms to attract the needed investor interest.

Table 2. Expensive IG-Rated Utility, Power Company, and Non-Financial Corporate Debt Issuances due to Limited Investor Demand During the COVID 19 Pandemic's Peak Market Disruption

Date	Issuer	Type	Size ($ MM)	Coupon	Issuance Ratings (Moody's/S&P)	Term	Spread	Orderbook
3/5/20	Daimler Finance NA	Unsecured	450	2.125%	A3/A-	5-year	+155.0 bps	1.28x
3/13/20	Zimmer Biomet Holdings	Unsecured	900	3.550%	Ba3/BBB	10-year	+262.5 bps	1.78x
3/17/20	Dominion Energy	Unsecured	400	3.300%	Baa2/BBB	5-year	+265.0 bps	1.25x
3/17/20	Dominion Energy	Unsecured	350	3.600%	Baa2/BBB	7-year	+275.0 bps	1.14x
3/17/20	Union Electric	Secured	465	2.950%	A2/A	10-year	+200.0 bps	1.40x
3/23/20	Humana Inc	Unsecured	600	4.500%	Baa3/BBB+	5-year	+412.5 bps	1.57x
3/23/20	Humana Inc	Unsecured	500	4.875%	Baa3/BBB+	10-year	+412.5 bps	2.63x
3/24/20	Chevron Phillips Chemical	Unsecured	650	5.125%	A2/A-	5-year	+462.5 bps	2.46x
4/2/20	Ross Stores	Unsecured	700	4.600%	A2/BBB+	5-year	+425.0 bps	1.43x
4/2/20	Ross Stores	Unsecured	400	4.700%	A2/BBB+	7-year	+425.0 bps	1.75x
4/2/20	Ross Stores	Unsecured	400	4.800%	A2/BBB+	10-year	+425.0 bps	2.00x
4/2/20	Ross Stores	Unsecured	500	5.450%	A2/BBB+	30-year	+425.0 bps	1.90x
4/2/20	Hyundai Capital America	Unsecured	550	5.750%	Baa1/BBB+	3-year	+550.0 bps	1.27x
4/2/20	Hyundai Capital America	Unsecured	600	5.875%	Baa1/BBB+	5-year	+550.0 bps	1.25x
4/2/20	Hyundai Capital America	Unsecured	650	6.375%	Baa1/BBB+	10-year	+575.0 bps	1.38x
4/2/20	Ryder System	Unsecured	400	4.625%	Baa1/BBB	5-year	+425.0 bps	1.81x
4/27/20	Delta Air Lines	Secured	3,500	7.000%	Baa2/BBB-	5-year	+661.0 bps	2.66x

Conversely, FPL was able to successfully raise debt capital during this same time. Indicative of its financial strength and solid reputational awareness among investors, the orderbook for this FPL issuance reached roughly $8 billion, with investor orders of more than seven times the $1.1 billion targeted capital raise. Despite this pandemic driven heightening of investor concerns, FPL's banking advisors were able to negotiate an approximate 50 basis point-reduction to the original offering spread at launch, for an attractive relative interest rate at a treasury spread of 237.5 basis points for a five-year term because of the Company's long-

> term financial strength and strong support of the investor community. (Before The Florida Public Service Commission, Florida Power & Light Company, Rebuttal Testimony Of Robert E. Barrett, Docket No. 20210015-EI, July 14, 2021, pp. 20-22).

Of the referenced companies, two of the companies are in Mr. Coyne's proxy groups (Entergy, and Appalachian Power, a subsidiary of AEP), but the data do not indicate the significance of the impacts on the markets for credit-worthy companies both in terms of access and the cost of capital.

82.0 Reference: Exhibit B1-13, RCIA 2.1

Preamble: The response states:

> "While FEI did not have any trouble attracting capital over the last three years due to the timing of its debt issuances, there were times during the COVID-19 pandemic when debt capital markets were experiencing significant volatility and access to debt was limited".

82.1 During the COVID-19 pandemic when debt capital markets were experiencing significant volatility and access to debt was limited, did the limitation on access apply just to FEI or was it also experienced by: i) other utilities and/or ii) other firms (apart from utilities) with ratings similar to FEI's?

Response:

When the debt capital markets were experiencing significant volatility and access to debt was limited, all companies were impacted with the impact being felt disproportionately by lower-rated entities.

83.0 Reference: Exhibit B1-13, RCIA 2.4

Preamble: The response states:

"FEI primarily benchmarks its capital raising metrics against other Canadian utilities identified in the Concentric report as it does not issue debt in the United States".

83.1 Please provide the results of FEI's most recent benchmarking of its capital raising metrics against other Canadian utilities.

Response:

Please refer below to an excerpt of benchmarking data that FEI regularly receives from major Canadian banks. FEI typically uses benchmarking data in terms of indicative corporate new issue spreads. For example, the below data suggests that had FEI issued 30-year bond the week of May 6, 2022, it could do so at an indicative yield of approximately 4.80 percent.

TD Securities

Canadian Debt Capital Market Update

Debt Capital Markets

Week Ending May 6th, 2022

Indicative Corporate New Issue Spreads

Levels shown are indicative spreads of where issuers could issue in the Canadian market. Spreads are vs the Government of Canada yield curve.

	Ratings				Term				
	DBRS	S&P	Moodys	Fitch	3	5	7	10	30
Media / Telco / Technology									
AT&T Inc.	-	BBB	Baa2	BBB+	150	170	203	230	300
Bell Canada	BBB(high)	BBB+	Baa1	-	150	170	195	220	270
CGI Inc.	-	BBB+	Baa1	-	145	170	193	220	265
Cogeco Communications Inc.	BBB(low)	BBB-	-	-	160	180	205	235	305
Rogers Communications Inc.	-	BBB+	Baa1	BBB+	165	185	210	240	310
Shaw Communications Inc.	BBB	BBB-	Baa2	-	170	190	215	245	310
TELUS Corp.	BBB(high)	BBB+	Baa1	BBB+	150	175	198	220	280
Thomson Reuters Corp	BBB(high)	BBB	Baa2	BBB+	145	165	187	215	265
Verizon Communications Inc.	-	BBB+	Baa1	A-	150	170	192	220	260
Utility									
Altalink LP	A	A	-	-	97	117	131	152	177
AltaLink Investments LP	BBB(high)	A-	-	-	112	132	146	167	202
Alectra Inc.	A	A	-	-	95	110	126	150	175
CU Inc.	A(high)	A-	-	A-	103	118	128	155	185
CU Ltd	A	BBB+	-	A-	118	133	155	170	200
Emera Inc.	-	BBB-	Baa3	BBB	140	155	175	205	N/A
Nova Scotia Power Inc.	A(low)	BBB+	-	-	118	133	143	163	200
Enbridge Gas Inc.	A	A-	-	-	105	122	143	170	195
EPCOR Utilities Inc.	A(low)	A-	-	-	100	110	130	155	185
FortisAlberta Inc.	A(low)	A-	-	-	108	123	133	153	185
FortisBC Inc.	A(low)	-	Baa1	-	118	133	144	163	200
FortisBC Energy Inc. (Terasen Gas)	A	-	A3	-	97	117	131	152	180
Fortis Inc.	A(low)	BBB+	Baa3	-	120	135	155	185	N/A
Énergir	A	A	-	-	100	115	130	150	180
Hydro One Inc.	A(high)	A-	A3	-	103	118	128	148	182
National Grid Electricity Transmission plc (Maple)	-	BBB+	Baa1	A-	138	153	170	200	255
Toronto Hydro Corp.	A	A	-	-	95	110	126	150	175
TriSummit Utilities Inc.	BBB(high)	-	-	-	150	170	184	205	260

Corporate New Issues

Announce Date	Issuer	Ratings	Amount ($mm)	Coupon	Maturity	Spread (vs. curve)
	- No New Issuance This Week -					

Bold Indicates TD Securities Lead / Co-Lead

Total 2022 YTD Issuance: $53.1 billion

Government of Canada Yield Curve

Term	Interpolated Yield	Bonds
2 year	2.636%	0.25% April 2024 2.50% June 2024
3 year	2.722%	1.25% March 2025 0.50% September 2025
5 year	2.800%	1.25% March 2027 1.00% June 2027

Term	Interpolated Yield	Bonds
7 year	2.916%	2.00% June 2028 2.25% June 2029
10 year	3.050%	1.50% December 2031 5.75% June 2033
30 year	2.994%	2.00% December 2051

83.1.1 If at all possible please include benchmark results for the four financial indicators set out in Table 6-4 of Exhibit B1-8 (page 33).

Response:

The following response 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. FEI requests that the response be kept confidential as it contains proprietary information and is under strict-use license. It 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.

[redacted]

[redacted] [redacted]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

84.0 Reference: Exhibit B1-8-1, Appendix C, page 161

84.1 Please provide the equivalent of Figure 6.8 assuming the Commission approved an equity ratio for FEI of: i) 40% and ii) 42.5%.

Response:

Concentric provides the following response:

Please see requested information below.

i)

Summary of Gas Results – Lesser inputs – at 40.0% equity

	Canadian Regulated Utilities	US Gas Utilities	North American Gas Utilities
CAPM	8.4%	8.0%	8.2%
Multi-Stage DCF	10.5%	9.4%	10.1%
Avg.	9.5%	8.7%	9.2%

ii)

Summary of Gas Results – Lesser inputs - at 42.5% equity

	Canadian Regulated Utilities	US Gas Utilities	North American Gas Utilities
CAPM	8.1%	7.7%	7.9%
Multi-Stage DCF	10.5%	9.4%	10.1%
Avg.	9.3%	8.6%	9.0%

85.0 Reference: Exhibit B1-8-1, Appendix C, pages 157 and 162-163 Exhibit B1-9, BCUC 60.3

Preamble: The Evidence states (page 157):

"His recognition that the Hamada equation can be used to adjust for differences in capital structure between the company for which the return is being established and the proxy group. While I have not adjusted my CAPM results for financial leverage, I agree that such an adjustment can be appropriate and would increase the ROEs for FEI and FBC".

BCUC 60.3 states:

"Mr. Coyne notes that Dr. Lesser suggested in his August 2021 report using the Hamada equation to adjust the authorized ROE for differences in financial leverage. That is one approach the BCUC might consider".

85.1 Please provide the equivalent of Figure 69 (page 162) but incorporate the Hamada equation adjustment using Mr. Coyne's recommended equity ratio of 45% for FEI.

Response:

Concentric provides the following response:

Please see requested information below.

Figure 1: Summary of Results - Gas[11]

	Canadian Regulated Utilities	US Gas Utilities	North American Utilities - Gas	Average
CAPM	10.86%	10.78%	10.84%	10.8%
Constant Growth DCF	11.61%	10.39%	10.99%	11.0%
Multi-Stage DCF	10.28%	9.53%	10.05%	10.0%
Risk Premium		9.97%	9.97%	10.0%
Average	10.9%	10.3%	10.7%	10.6%
Avg CAPM and Multi-Stage DCF	10.6%	10.2%	10.4%	10.4%

[11] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for U.S. risk premium results.

85.1.1 Please include a schedule setting out how the results for the Hamada equation adjustment were derived.

Response:

Concentric provides the following response:

Please refer to Attachment 85.1.1 for the requested schedule.

85.2 Please provide the equivalent of Figure 69 (page 162) but incorporate the Hamada equation adjustment using the currently approved equity ratio of 38.5% for FEI.

Response:

Concentric provides the following response:

Please see requested information below.

Figure 2: Summary of Results - Gas[12]

	Canadian Regulated Utilities	US Gas Utilities	North American Utilities - Gas	Average
CAPM	12.05%	11.93%	12.00%	10.8%
Constant Growth DCF	11.61%	10.39%	10.99%	11.0%
Multi-Stage DCF	10.28%	9.53%	10.05%	10.0%
Risk Premium		9.97%	9.97%	10.0%
Average	11.3%	10.5%	10.8%	10.9%
Avg CAPM and Multi-Stage DCF	11.2%	10.7%	11.0%	11.0%

85.2.1 Please include a schedule setting out how the results for the Hamada equation adjustment were derived.

[12] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for U.S. risk premium results.

Response:

Concentric provides the following response:

Please refer to Attachment 85.2.1for the requested schedule.

85.3 Please provide the equivalent of Figure 70 (page 163) but incorporate the Hamada equation adjustment using Mr. Coyne's recommended equity ratio of 40% for FBC.

Response:

Concentric provides the following response:

Please see requested information below.

Figure 3: Summary of Results - Electric[13]

	Canadian Regulated Utilities	**US Electric Utilities**	**North American Utilities - Electric**	**Average**
CAPM	11.74%	11.87%	11.62%	11.7%
Constant Growth DCF	11.61%	9.57%	9.87%	10.4%
Multi-Stage DCF	10.28%	8.82%	9.07%	9.4%
Risk Premium		10.01%	10.01%	10.0%
Average	11.2%	10.1%	10.1%	10.5%
Avg CAPM and Multi-Stage DCF	11.0%	10.3%	10.3%	10.5%

85.3.1 Please include a schedule setting out how the results for the Hamada equation adjustment were derived.

Response:

Concentric provides the following response:

Please refer to Attachment 85.3.1 for the requested schedule.

[13] DCF results are based on 90-day average stock prices for proxy group companies. Results include 50 basis points for flotation costs and financial flexibility except for U.S. risk premium results.

Attachment 61.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 62.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 62.2.1

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 63.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 69.1

REFER TO LIVE SPREADSHEET MODEL

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FILED CONFIDENTIALLY

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Attachment 70.2

REFER TO LIVE SPREADSHEET MODEL

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Attachment 70.3

REFER TO LIVE SPREADSHEET MODEL

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Attachment 75.2

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Attachment 78.3

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Attachment 85.1.1

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Attachment 85.2.1

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Attachment 85.3.1

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